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THE EVOLUTION OF ENERGY INFRASTRUCTURE IN THE UNITED STATES AND HOW LESSONS LEARNED FROM THE PAST CAN INFORM FUTURE OPPORTUNITIES

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

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THE EVOLUTION OF ENERGY INFRASTRUCTURE IN THE UNITED STATES AND HOW LESSONS LEARNED FROM THE PAST CAN INFORM FUTURE OPPORTUNITIES

THURSDAY, FEBRUARY 8, 2018

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

The Committee met, pursuant to notice, at 10:07 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.

Infrastructure. Lots of people have been talking about infrastructure. Certainly, here in the Energy Committee, we have been doing it for quite some time.

Senator Cantwell and I, in our bipartisan bill that we worked to move last session, last Congress, I think really laid the groundwork for some of the good infrastructure pieces when we think of energy.

During his State of the Union address, President Trump called for a renewed focus on our nation's infrastructure. And again, here at the Energy Committee, we have been working to improve our nation's energy infrastructure for the past several years, largely focusing on the roadblocks that hinder responsible development, challenges related to cybersecurity and the pursuit of innovative technologies.

Our nation's energy delivery systems have benefited from significant innovation over the years. Today's hearing will put current infrastructure opportunities into perspective by examining how America's energy, from production to generation to distribution, has evolved over time. This is an opportunity to look at what we have, how we came to have it and to examine which policies helped the effort.

I often think back to the development of the Trans-Alaska Pipeline System (TAPS) during the 1970s. Prudhoe was the largest oilfield ever discovered in North America, but we needed a way to transport the oil from the remote North Slope. After much study and debate, Alaskans determined that a pipeline was our best option, which required Congressional approval in the midst of an oil crisis.

Since TAPS came online in 1977, the 800-mile pipeline has successfully transported more than 17 billion barrels of oil from the North Slope to an ice-free port in Valdez. More than half of the pipeline runs above ground, which is a necessity given Alaska's prevalent permafrost terrain. But really, it is truly an engineering marvel.

It is a lifeline for Alaskans. It creates jobs, provides revenues and has enabled the creation of our Permanent Fund. It is also a critical national security asset for all Americans, particularly those along the West Coast.

Today's technologies, like fracking, have allowed us to reach oil and gas resources that were previously unattainable. And technological improvements, like horizontal drilling, have enabled industry to shrink their footprint while reaching resources miles away from the drill site. One thing that has not changed is that we still need pipelines to deliver these resources to refineries and natural gas plants. It has just, unfortunately, become a little bit harder to build them.

Perhaps no asset has seen more innovation and evolution than our nation's energy grid. I think we all recognize that the grid is no longer just an energy delivery system for large, centralized generation assets.

Distributed generation, microgrids and energy storage now bring electricity closer to home, changing the way consumers interact with their electricity providers. At the same time, we have seen significant changes in energy consumption. Efficiency improvements and retrofits allow us to use less energy to power and heat greater space at a lower cost. In some of Alaska's more remote communities, simply by switching streetlights to more efficient LEDs, we have seen savings in tens of thousands of dollars annually.

Layered on top of the infrastructure evolution is the digital revolution. The increased digitalization of our nation's energy delivery system provides numerous benefits. Real-time monitoring can allow for system optimization and identify potential issues in their earliest stages. Better data assists consumers in making informed choices about their energy usage.

At the same time, increasing the amount of internet connections also increases the number of access points, which can leave our critical infrastructure vulnerable to potential bad actors. Determining how best to secure our infrastructure from ever-increasing cybersecurity threats is one of the biggest security challenges that face our nation today.

As we consider the evolution of energy infrastructure, it is impossible to ignore the impact of government policy. There have been times when Congress has made a positive impact, such as recognizing, again, the value of TAPS during an energy crisis. But too often we have seen failed government attempts to impose outcomes or, perhaps, pick winners and losers and we do not always pick the winners. It is important then that we use the lessons learned from the past to inform future Congressional actions.

We have a distinguished panel of witnesses here today. I will introduce them all in a moment.

But now, let me turn to Ranking Member Cantwell for your comments.

STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON

Senator CANTWELL. Thank you, Madam Chair, and thanks for holding this important hearing on a variety of issues as it relates to our nation's energy infrastructure. I know that you and I have been on the same page for a couple of years now about making major investments in using the Quadrennial Energy Review as a framework for how we move forward.

Hopefully our colleagues, as we move more to a larger infrastructure discussion in the Senate, will look at some of these issues that we are talking about today.

I, too, want to welcome the witnesses. Some people want to know how you build an ecosystem of mind share and expertise. Well, I feel like the panel in front of us is that ecosystem, particularly for the Pacific Northwest.

Mr. Allen from McKinstry, with whom the Chair and I had an opportunity to tour the facility in Seattle, looking at how energy efficiency was saving local school districts money; Mr. Mezey, from Itron in Spokane; but I need to point out that Mr. Moeller, also, we claim you as a Northwest native.

[Laughter.]

So there is something to be said for building, and I would point out that our public power representative is here too. That is what made this ecosystem happen and the continued technology and focus and interest in keeping ahead.

So thank you all for being here. It is a delight to have this panel.

Three decades ago, the average U.S. home used electricity to power a television and a couple large appliances and a few small appliances. Americans are now connected to the Internet and using multiple televisions and appliances and charging computers and tablets and cell phones. And now, even, charging electric cars and generating their own power with solar panels.

Consumers and businesses are demanding new services and new technologies, and our electricity grid needs to keep pace with that, and also the growing threat of cybersecurity attacks.

We need to invest in modernizing our infrastructure to meet demands, help lower consumer's bills and provide security. And we know that is a good return on investment. We learned from the Recovery Act that when $1 billion was invested in smartgrid technologies, it created nearly $7 billion in economic output. The investment created nearly 50,000 jobs and more than $1 billion in tax revenues back to the government.

Smartgrid and energy efficiency technologies can help reduce the need for expensive peak power and shift loads off peak. The Department of Energy's Pacific Northwest Smart Grid Demonstration Project, partnered with Avista, another one of our components to that ecosystem, in Eastern Washington and other utilities in the region and they found the use of smart meters help consumers reduce their energy consumption by anywhere from 4.5 to 9 percent. These real savings for consumers are a part of what is an important record in the technology performance report that highlights the outcomes of those projects.

Beyond the economic impacts, smartgrid technology has an impact on the environment as well, and Pacific Northwest National

Labs estimated that investments in smartgrid and intelligent buildings can reduce U.S. carbon emissions anywhere from 12 percent by 2030.

The Pacific Northwest, as I said earlier, has always been about this modernization. I guess that is because of the realization of how effective and efficient affordable electricity is in building your economy over and over again. Some people just recently on a trip home to the Northwest said, some people would think that if you had cheap electricity, why would you keep building in energy efficiency because you already have affordable, cheap electricity? But what happens is you have the mind share and awareness of how much that drives your economy, so you keep making more and more investments in it.

I think that is why we are hearing from Mr. Allen from McKinstry, Mr. Mezey from Itron, and several other witnesses today.

In the 1970s, companies transitioned from designing and retrofitting buildings to cutting waste, saving money and increasing comfort and they continue to embrace the smart building and energy efficiency work that is so important to new schools and data centers.

McKinstry has grown from a company of just 6 to more than 1,800 employees. Itron, from Liberty Lake, Washington, is a leading manufacturer of innovative grid and smart metering technology. Their solutions help cities, utilities and consumers better manage energy and water resources and move toward a cleaner energy economy. Both these companies are developing next generation technology that, I believe, should be part of our energy infrastructure investment in the future.

As I mentioned, cybersecurity, I believe, is a critical part of our infrastructure investment for the future. From 2012 to 2016, the number of cyberattacks against U.S. critical infrastructure more than doubled. In 2013 and 2014, energy infrastructure was the number one cyber target of all U.S. critical infrastructure.

The Russians and foreign actors have the capability to do significant damage to our economy by bringing down that electricity grid. In October, NBC News reported that hackers linked to North Korea targeted U.S. electric power companies. If we don't make the necessary investments here to protect against cyberattacks, we are creating the opportunity for people to create widespread havoc on our grid.

At his confirmation hearing last year, Secretary Perry committed in the record that he would support spending on cybersecurity and I hope he will follow through on this commitment.

I hope today we also hear about the workforce needs of these industries and sectors. The Department of Energy's Quadrennial Energy Review estimated that we needed 1.5 million new energy jobs to fill by 2030, including 200,000 workers with STEM skills. I know how much McKinstry focuses on this at their facility in the state being a lead on the discussion of how we get more STEM workers. Our energy infrastructure is upgraded with new technology to be smarter, so the workforce needs to also be upgraded with those skills.

That is why we need to make this infrastructure investment and I hope that our colleagues, after today's hearing, will see the benefit of it, no matter what the source of base energy is, energy efficiency is a big winner for our consumers and businesses.

Thank you.

The CHAIRMAN. Thank you, Senator Cantwell.

We will now begin with testimony from each of our witnesses.

Again, welcome to each of you. Thank you.

I know several of you have come, as Senator Cantwell says, from the Pacific Northwest. We appreciate the fact that you are giving your time here with the Committee this morning.

We will be led off by Mr. Phil Moeller, who is the Vice President of Edison Electric Institute (EEI). You have been before this Committee numerous times, in different capacities, formerly with your role at the FERC, but we welcome you back, Mr. Moeller.

Mr. Philip Mezey, who is the CEO of Itron.

And John Di Stasio, the President for the Large Public Power Council. We welcome you this morning.

As Senator Cantwell mentioned, we had an opportunity to visit with Mr. David Allen, who is the Executive Vice President of McKinstry. It was good to be with you at your facility and to really understand so much of what is going on. It was really very enlightening. I appreciate that.

Dr. Ken Medlock is with the Committee this morning. He is a senior fellow with the Baker Institute for Public Policy at Rice University. We welcome you.

And also, Mr. Don Santa, also not a stranger to this Committee, you have been before us before. We welcome you back as the President and CEO of the Interstate National Gas Association of America, INGAA.

Thank you all.

Mr. Moeller, if you would like to begin this morning? We would like to keep comments to about five minutes, and your full statements will be included as part of the record.

STATEMENT OF HON. PHILIP D. MOELLER, EXECUTIVE VICE PRESIDENT, BUSINESS OPERATIONS GROUP & REGULATORY AFFAIRS, EDISON ELECTRIC INSTITUTE

Mr. MOELLER. Well, thank you, Chairman Murkowski, Ranking Member Cantwell and members of the Committee. I'm Phil Moeller with EEI. Thank you for having us and speaking on this important topic.

EEI is the trade association of the investor-owned energy companies throughout the country. We serve over 220 million people out of 60 international members.

We appreciate, also, the fact that you're focusing on infrastructure and transmission. You asked me to go through a little bit of a history of the transmission system with some lessons learned going forward.

One of the things that's important about this is that, I think, transmission is generally, kind of, the unappreciated segment of American infrastructure, partly because it does remarkable things and it's very reliable, so it's, kind of, invisible. But the system is getting more and more reliable according to NERC and to think about instantly being part of an energy delivery system that provides electricity to over 320 million Americans is remarkable in itself.

It's important, also, because the transmission system in this country has been called the most complex machine in the world. And that, in itself, is remarkable. We have connections with Mexico. We have extensive connections with Canada. Canada really doesn't have much of an east-west transmission system so they rely on us. And we have three interconnections in this country. The one in the East, which is roughly the eastern two-thirds of the country, one in the West and one solely within Texas, known as ERCOT.

The great thing about transmission is that it provides a lot of optionality. Optionality similar to a robust system of highways and roads. Highways get congested, so do power lines. You have a robust system, you can decrease that congestion, that lowers costs. A transmission system can allow for access to lower cost energy over a larger footprint, also resources that are generated far from load. A lot of our renewable resources are far from load and it contributes to the reliability and the resiliency of the system, all at, I would argue, a very surprisingly low price, about 11 percent on average of the typical customer's bill.

In terms of the history, our nation really started off as a series of distributed microgrids. And you can see the first one up in Manhattan at the Pearl Street Station. And pretty soon people figured out that it was a lot more efficient and it was a lot less costly and more reliable if we connect these systems through a transmission system.

And so, gradually, people did and then created these transmission power pools, the first of which was created in 1927, when the states of Pennsylvania, New Jersey and Maryland, PJM, got together. That footprint is now 13 states and the District of Columbia.

So gradually more and more of these power pools were developed and we decided that we should get coal out of people's basements and instead burn it in bigger power plants far from cities, cheaper, more efficient, generally better for customers throughout the world, throughout the country.

In 1965, we had a major event. The Northeast blackout led to, eventually, the creation of the predecessor of NERC, realizing that voluntary standards were necessary to prevent blackouts again.

Another major event in 1992, you, as Congress, passed the Energy Policy Act. That lead to a couple of things. Mostly though, emphasizing this concept of open access of the transmission system so that everybody could get on it under comparable rates, terms and conditions. That led to a very competitive, vibrant, wholesale market. The premise being, again, open access of the transmission system that was incorporated by Order No. 888 from FERC in 1996.

And 2003 was another major event in which the Northeast blackout affected 50 million customers. Again, Congress responded in 2005 with the Energy Policy Act directing FERC to designate an electric reliability organization, which is NERC, to have mandatory standards on the transmission system that were lacking before that. FERC has subsequently adopted scores of standards that are developed through the NERC process.

The other part of the 2005 bill that was significant is that Congress recognized there had been underinvestment in the transmission system for several decades, so part of that very extensive Act was to promote transmission incentives which did lead to a period of expansion of the transmission system and it was effective.

However, today we face a number of uncertainties that are based on a number of factors.

First that, as you mentioned, siting and permitting is quite a challenge and, under your bipartisan bill that you introduced, some of those issues are addressed to make more accountability, timelines for the resource agencies particularly, and vegetation management is related to that so that power lines can be secured and run efficiently as well.

My former colleagues at the FERC have a number of issues that they can address to create better certainty in this investment climate. Dealing with the uncertainty over ROEs after a court remand, dealing with these ongoing pancaked rate cases which is a challenge, probably not the intent of the Federal Power Act when rate cases can go on and on.

Transmission incentives have been limited.

We also have a little bit of uncertainty over Order No. 1000 and what it means for various planning regions throughout the country.

But because these are such long-lived and capital-intensive projects, often 40 and 50 years or longer, and in terms of how long they're used, the investment certainty up front is very important and both Congress and my former colleagues at FERC can make a number of decisions and actions that will increase the certainty of these investments.

Again, thank you for having me. I look forward to answering any questions.

[The prepared statement of Mr. Moeller follows:]

Statement of

Philip D. Moeller
Executive Vice President
Business Operations Group & Regulatory Affairs
Edison Electric Institute

Hearing on
Energy Infrastructure

Committee on Energy and Natural Resources
United States Senate
February 8, 2018

Chairman Murkowski, Ranking Member Cantwell, and members of the Committee, I am Phil Moeller of the Edison Electric Institute (EEI), and I thank you for the opportunity to speak before you today. EEI is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States. In addition to our U.S. members, EEI has more than 60 international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members. I have previously addressed this Committee several times as a two-term member of the Federal Energy Regulatory Commission (FERC).

Thank you also for holding this hearing and focusing on perhaps the most unappreciated segment of our nation's vital infrastructure: the electric transmission grid. I was asked to provide a brief high-level history of how transmission developed in the nation, with an emphasis on lessons learned to inform future policy decisions.

First, why is this an important topic? Our nation's energy grid has been called the most complex machine in the world[1], and it serves as the bulk power backbone that delivers electricity instantly to more than 320 million customers. It is perhaps unappreciated because of its amazing reliability and its contribution to resiliency. According to the North American Electric Reliability Corporation (NERC), even with all the changes underway in the electricity sector, the bulk power system remains highly reliable and resilient, showing improved reliable performance year over year.[2]

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[1] See Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World (Joseph Henry Press 2006). See also Jack Casazza and Frank Delea, Understanding Electric Power Systems (Wiley-IEEE Press, 2d ed. 2010).
[2] Testimony of Gerry Cauley, Subcommittee on Energy, House Committee on Energy and Commerce, September 14, 2017. See also "State of Reliability 2017" (NERC, June 2017).

The nation's energy grid consists of some interconnections with Mexico and extensive connections with Canada, which has much more of a north to south delivery system with the United States than between the Provinces. It currently comprises three major "interconnections" consisting of roughly the Eastern two-thirds of the continent (the Eastern Interconnection), the rest of the continent (the Western Interconnection), and an interconnection within the boundaries of Texas known as the Electric Reliability Council of Texas (ERCOT). Under the Federal Power Act, Alaska and Hawaii are not considered part of this "bulk power" system.

Transmission serves such a vital role because it provides optionality similar to a robust system of highways for transportation. A robust transmission system alleviates costly congestion, provides access to lower-cost generation, increases the reliability and resiliency of electricity delivery, and can flexibly adapt to changes in public policy and sources of electricity generation. This optionality value comes at a surprisingly small cost: on average about 11 percent of the total amount of a customer's total electricity bill.[3]

Our transmission system was first developed more than 100 years ago as policy makers and energy companies realized that the optionality created by increased connectivity would provide greater reliability over a wider area and would provide access to more affordable electricity depending on the resources available over a larger transmission footprint. Of note, most providers of electricity were vertically integrated and owned generation, transmission, and the distribution network. The first "Power Pool" as it was known consisted of assets located in Pennsylvania, Maryland, and New Jersey and was formed in 1927. It was the predecessor to the "PJM Interconnection" that presently consists of transmission assets in 13 states and the District of Columbia.

After the formation of PJM, other power pools formed throughout the nation. Over the decades, the transmission system expanded as the nation grew and more electricity was produced at centralized power plants often located outside of metropolitan areas, leading to more affordable electricity. A pivotal event was the 1965 Northeast blackout that resulted in the loss of electricity service in several states and Ontario. This event highlighted the interconnected nature of the system and the need for better coordination, and led to the formation of NERC's predecessor in 1968. Voluntary standard operating procedures were developed.

Due in part to policies promoted in the 1992 Energy Policy Act, momentum grew during the 1990s to provide more wholesale electric competition. This was enabled by the concept of "open access", which allows generation assets to access the transmission network under comparable rates, terms, and conditions. Open access was the driving principle behind FERC's landmark Order No. 888, adopted in 1996. Order No. 888 led to the creation of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), essentially two

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

terms describing the same concept: independent operators of regional transmission systems that implement the concept of open access through system operations and the rules that govern these operations. FERC revisited Order No. 888 in 2005, leading to an updated version of these policies focusing on transmission planning through the 2007 issuance of Order No. 890.

The 2003 blackout, affecting more than 50 million customers throughout the eastern United States and Ontario, highlighted the importance of transmission system standards and rules. Congress responded with language in the 2005 Energy Policy Act (EPAct 2005) directing FERC to designate an entity as the Electric Reliability Organization, the role that NERC has today. Since 2006, FERC has adopted scores of mandatory reliability standards that are developed in the NERC standard-setting process.

Seeking to end a two-decades-long period of underinvestment in transmission, Congress dedicated several sections of EPAct 2005 to promoting the expansion and modernization of the nation's energy grid. Among many other policy provisions, EPAct 2005 included a directive to FERC to incorporate specific transmission incentives, recognizing that capital investments in electric transmission infrastructure produce significant benefits for electric customers and society as a whole.

A period of transmission investment began. Recognizing that, from inception, major transmission facilities often take more than 10 years to complete, EEI's member companies invested $20.8 billion in transmission infrastructure in 2016 and expect to invest an additional $90 billion in the transmission system through 2020 to make it more efficient, more dynamic, and more secure and to continue to provide customers with the affordable, reliable, safe, and increasingly clean energy they need. However, looking at an aggregate national projection for investment does not mean all transmission needs are being met in all regions or that the level of investment is adequate, particularly as we look toward the future. Moreover, planned investment and actual investment are not the same; we have seen planned investments canceled.

In 2010, FERC released Order No. 1000, an attempt to create more competition in the transmission sector by promoting additional regional planning processes and requiring competitive bidding on certain projects within regions. Around the same timeframe, anticipated transmission investment slowed in response to a slower economy and reduced load growth. From my perspective, uncertainty over the implementation of Order No. 1000, along with uncertainty over the pace and extent of environmental regulations, contributes to the slowdown of expected transmission investment.

This is problematic. Looking forward, increased transmission investment is needed for both the expansion of the system to bring energy from new resources to demand centers and to maintain, enhance, and replace aging infrastructure. Much of the nation's transmission system is more than 40 years old, with some facilities many decades older.

EEI members are not advocating for additional federal funds for transmission investment, but rather increased certainty when proposing to make these significant, long-term infrastructure investments. Again, as these assets usually will be in use for 40 years or longer, increased certainty at the time of the investment, as well as over its long lifetime, is crucial.

Several factors have created uncertainties in the present investment climate. As stated earlier, the process of planning, siting, and constructing major transmission facilities often takes more than 10 years to complete. Siting and permitting reform is crucial for investment, as well as for effective operation and maintenance after facilities are built. These efforts should emphasize better coordination of state and federal agency reviews, with reasonable deadlines for agency action and increased decisional accountability. Congress can help by passing legislation to improve permitting and siting processes and other regulatory reviews under the National Environmental Policy Act (NEPA) and other statutes without undermining important environmental protections.

Specific areas for improvement include FERC hydropower relicensing, permitting and siting of transmission lines and natural gas pipelines, and vegetation management on and adjacent to rights-of-way across federal lands. The bipartisan Energy and Natural Resources Act (S. 1460) introduced by Chairman Murkowski and Ranking Member Cantwell includes provisions addressing many such energy infrastructure issues, as do other Senate and House bills.

FERC also can improve the climate of certainty by addressing several areas. Topping this list is the need to reform the process of estimating the allowed Return on Equity (ROE) for transmission investments, which is also necessary based on the DC Circuit's April 14, 2017, remand of Order No. 531. EEI, along with ScottMadden, recently has released a White Paper entitled "Transmission Investment: Revisiting the Federal Energy Regulatory Commission's Two-Step DCF Methodology for Calculating Allowed Returns on Equity." The paper outlines several options for FERC to create a more stable environment for the ROE component of these infrastructure investments.

Related, but separate from the issue of ROEs, is the future of transmission incentives mandated under EPAct 2005. Due to the formula currently in place for ROEs, incentives are often inappropriately capped. Incentives also have been reduced inappropriately or threatened after they have been awarded and after long-lived investment decisions have been made based on those very incentives. Because incentives are a key factor when transmission investments are made, certainty will be increased when FERC clarifies that previously approved incentives are allowed to remain in place.

FERC also can address the current practice of allowing multiple ongoing transmission rate complaint cases, often referred to as "serial" or "pancaking" of these cases. Under the Federal Power Act, the refund periods for transmission rate complaints specifically are limited to 15 months after cases are filed. Under current Commission processes, these cases rarely, if ever, are concluded within 15 months. In the absence of Commission determinations within 15 months, complaints subsequently have been filed shortly after the 15-month statutory limit, effectively extending the refund period indefinitely. For the transmission owners in New England, this practice has led to uncertainty over the actual transmission rates and revenues dating back to 2011. My observation is that this outcome may not be in line with the original intent of Congress. This increased uncertainty places burdens on energy companies and customers, who ultimately face higher borrowing costs. EEI soon will release another White Paper suggesting ways FERC can address this ongoing practice that again creates uncertainty surrounding these major infrastructure investments.

In addition to the challenges of siting, permitting, and financing these infrastructure investments, figuring out who pays and how much, known as "cost allocation," is a challenging process. Over the lives of these investments, electric load will change and electricity flows change. Very generally, to the extent FERC can increase certainty in cost allocation formulas, investment certainty will increase.

Thank you again for the opportunity to testify before the Committee, and I look forward to any questions you may have.

The CHAIRMAN. Thank you, Mr. Moeller, we appreciate you being here.

Mr. Mezey.

STATEMENT OF PHILIP MEZEY, PRESIDENT AND CEO, ITRON, INC.

Mr. MEZEY. Thank you, Madam Chair Murkowski, Ranking Member Cantwell, distinguished Senators.

So as we've heard, Itron is a company that started about 35 years ago, actually, in Hauser Lake, Idaho, and has now grown, headquartered outside Spokane, Washington, to over $2 billion in revenue and 8,000 employees.

The company started on the simple premise of trying to make it easier to collect electricity, gas and water information. That mandate has really grown well beyond that, that we realize that having better connections and better information from the distribution grid allows utilities to understand how effectively they're distributing electricity, gas and water and how effectively customers are using it. We have relatively little of this information historically and now are getting much more insight about how we can better manage and measure and secure the grid.

I just wanted to provide a couple of very quick examples. Because we face the challenge which, as we've seen estimates as high as $1 trillion of required investment into aging infrastructure. And the question is, how do we manage that kind of investment and target it more effectively? Because the kind of smart technology from smart metering to networks and sensors that can be placed out there give us the tools to allow us to understand where to invest the money and when so that we can allocate capital more effectively. We can manage our existing assets for longer and we can reduce operations and maintenance costs so that we can help our utilities to be more successful and, of course, help our customers to understand more effectively how they're using these critical resources.

As an example, Center Point Energy, which is the utility of Houston, was just hit by Hurricane Harvey and managed with this smarter infrastructure to restore power much more quickly than they had before. They saved 45 million outage minutes. So the grid has become more resilient, and the utility is providing more effective power. They've improved their overall reliability by 25 percent. As a result of the smart infrastructure that they've invested in, they've saved over 17 million truck rolls because they're able to see what's going on out in the field. This has been a tremendously positive business case, and they continue to explore how they can drive even greater benefits.

Hurricane Irma took out 4.4 million customers in Florida who all were restored under ten days as a result of the smart investments, grid investments, that they had made.

On the gas side, through pressure and flow sensing, we're able to more quickly identify where potential leaks will occur. We have corrosion monitoring, pressure sensing and are starting to deploy methane sensing to improve the safety of the grid and also to be able to target and understand where problems will occur.

Using the smart technology, we can also defer when investment is necessary. So our customer, Central Hudson, has implemented a demand response program. And that program allows them to balance their load so that they can defer a new generation asset. They've been able, through their demand response program, to get back 6 megawatts of peak power of a program that's intended to get 16 megawatts of power reduction. So again, manage infrastructure investments and be able to defer capital when necessary.

A really exciting development in our space is the integration between the electric utilities and cities which we're starting to see more. EEI recently joined the Smart Cities Council. I just wanted to cite an example, Envision Charlotte, in which Charlotte, teaming with Duke and Itron among others, have reduced energy usage in downtown Charlotte by 19 percent. This is a very significant reduction that drives economic vitality in Charlotte.

We're also involved in a deep partnership in Spokane, a project called Urbanova, in which a number of local players are coming together in order to create better outcomes in downtown Spokane.

We deeply believe that the investments in this smartgrid technology are not only showing basic business case benefits, they're helping utilities to better understand how to allocate scarce resources, manage their assets more effectively and, as Senator Cantwell mentioned, prepare for the 21st century grid requirement which is a more dynamic grid and a better connection to customers to give them better information over time.

I thank you very much. Happy to answer any questions and for Itron to be a resource at any point to you or your staff.

[The prepared statement of Mr. Mezey follows:]

Full Committee Hearing on Energy Infrastructure

U.S. Senate Committee on Energy and Natural Resources

February 8, 2018

Prepared Statement of Philip Mezey,
President and CEO, Itron, Inc.

SUMMARY

Highlighting case studies from Texas, New York and North Carolina, Mr. Mezey will discuss how smart technologies can help utilities and cities address the critical challenge of aging electric, gas and water infrastructure. The right technologies, deployed in the right places, gives utilities and cities:

- Operational data to better prioritize infrastructure replacement (e.g. new smart technology can detect voltage impedance in transformers, giving utilities a valuable preventative maintenance tool).
- Opportunities for more shared infrastructure (e.g. a single, secure and interoperable communications network can be shared across multiple entities and used for multiple utility and city-service applications).
- Opportunities to defer the need for new infrastructure by using cloud-based services and non-wires alternatives (e.g. demand response programs).

Full Committee Hearing on Energy Infrastructure
U.S. Senate Committee on Energy and Natural resources
Prepared Statement of Philip Mezey, President and CEO | Itron, Inc.

Itron
www.itron.com

Good morning Madam Chair Murkowski, Ranking Member Cantwell and distinguished Members of the Committee. Thank you for the opportunity to speak to you today about such a critical topic, energy infrastructure in the United States.

My name is Philip Mezey, and I am the president and CEO of Itron, a global technology and services company dedicated to the resourceful use of energy and water, based in Liberty Lake, WA. From humble beginnings in a garage in Hauser Lake, Idaho, Itron has grown into a $2 billion company with over 8,000 employees around the world. We provide comprehensive solutions (such as meters, sensors and software and services) that connect systems to measure, manage and analyze energy and water for utility and smart city customers.

Itron was founded on the premise that "there has to be a better way," and I believe we can apply this premise to address the needs of our nation's energy infrastructure. Over the last four decades, we've helped utilities and cities in the U.S. and around the world make the most of what they have. Our technology helps our customers operate more efficiently, engage with customers more effectively and be resourceful stewards of the world's electricity, gas and water. We can apply the same thinking and the right technology, in the right places, to make the most of our nation's energy infrastructure and ensure that we continue to deliver safe, reliable and affordable energy to customers across the U.S.

THE ENERGY INFRASTRUCTURE CHALLENGE
What can be done? The trillion plus dollars that it would take to replace and upgrade our aging utility infrastructure are not available. Therefore, it is imperative we deploy technologies to get the most out of our existing infrastructure and to manage upgrades as funding becomes available. Current smart technologies have proven effective in getting the most out of our existing infrastructure, offering opportunities to share investments and benefits, and in some cases, displacing the need for new infrastructure.

OPPORTUNITIES + SUCCESS STORIES
The key to optimizing our current system is to embed more intelligence into our nation's power grid. More detailed data and operational visibility allows us to identify assets that need to be replaced first. Intelligent devices can also take action when and where it's needed within the system to help prolong the life of those assets, shift load and raise awareness of potential issues. For example, today's smart meters can detect voltage impedance in transformers, giving utilities a valuable preventative maintenance tool which allows them to better prioritize limited ratepayer funds.

When we think about the critical services enabled by our nation's electricity, gas and water providers, the right technology not only makes these providers more operationally efficient and effective, but also helps them deliver those services with both greater reliability and resiliency. Here are a few examples.

CenterPoint Energy (CNP) in Houston has deployed advanced metering infrastructure (AMI) technology across its electric and natural gas service territory. With this technology, CNP has saved over 1.7 million gallons of gasoline and 15.6 metric tons of CO_2, reduced "truck rolls" (visits to customer sites for routine activities like meter disconnects and reconnects) by over 17 million, and improved overall electric service reliability by 25 percent—all of which are great operational gains for CNP, but also enhance safety, increase system dependability and benefit ratepayers.

When Hurricane Harvey made landfall in August 2017, over 250,000 people in Texas lost power. The effects on CNP's customer base were widespread and immediate. But aided by the AMI system it had installed, CNP was able to recover and reconnect people to power very quickly—avoiding an estimated 45 million outage minutes for its customers. AMI technology on gas meters also helped CNP rapidly identify potential gas leaks in its distribution system, dispatch crews and alleviate potentially dangerous situations without incident.

The right networking infrastructure forms the foundation for smart, connected cities. With a single, secure and interoperable communications network shared across multiple entities (utilities, city service providers, businesses and more) that can leverage a variety of applications (energy and water delivery management, streetlights, parking, waste, building management and so on) can make our cities more livable. This type of network fundamentally changes how cities think about ubiquitous connectivity, machine-to-machine learning, distributed intelligence, cloud applications and more personalized experiences for consumers. The right network technology also accelerates innovation, helps develop public/private partnerships and nurtures an ecosystem of applications that can improve city services.

One of the best examples of what's possible with smarter cities comes from Envision Charlotte, a first-of-its-kind collaboration in uptown Charlotte, NC. With smart technology connected across energy, water, waste and air, Envision Charlotte is harnessing the power of its smart infrastructure to reduce consumption and waste, and ultimately reduce the cost of doing business in the area. And it's working—Envision Charlotte has achieved a 19% reduction in energy usage, equating to more than $26M in savings. The city has also realized a 19% reduction in CO_2, which is equivalent to removing over 11,000 cars from the road.

We also have the opportunity to defer significant investment in power generation and delivery assets with a greater focus on distributed energy resources—and particularly demand response programs. The use of smart technology in homes and businesses drives change in the consumption habits of electric utility customers, allowing providers to better match the demand for power with supply, shift peak load and better manage the electricity they have.

As a part of New York's Reforming the Energy Vision (NY REV) program, Central Hudson Gas & Electric is leveraging demand response to reduce the burden on existing energy infrastructure, rather than relying on investments in centralized generation (peaking power plants) and transmission/distribution assets, also called a non-wires alternative. The program includes a demand response management system, customer portal and incentives to help curtail peak load in rapidly growing areas of Central Hudson's service territory. The company has achieved 5.9 megawatts of load reduction in its first program year, and is on track to hit 16 MW of demand reduction once the program hits full maturity.

And finally, the digital transformation of the utility industry is putting greater emphasis on cloud-based solutions, which are a more secure and cost-effective option when compared to utility staffed, managed and maintained on-premise data centers—a $25,000 investment in cloud technology equals about $100,000 in on-premise investment.

With large organizations like Microsoft building and supporting cloud infrastructure, the move to the cloud also helps make utility data more secure. Microsoft spends over $1 billion annually on security and data privacy—much more than individual utilities can to secure our nation's grid from threats. In one study, prior to migration to the cloud, 60% of individuals polled were concerned about data security and privacy; but after migration, 94% of those polled felt they were more secure and more risk-compliant in the cloud than they had been on-premise.

The right technology, deployed in the right places, can dramatically bolster our energy infrastructure across the U.S. and help us make the most of our natural, financial and human resources.

The CHAIRMAN. Thank you, Mr. Mezey, we appreciate you being here.

Mr. Di Stasio, welcome.

STATEMENT OF JOHN DI STASIO, PRESIDENT, LARGE PUBLIC POWER COUNCIL

Mr. DI STASIO. Thank you very much, Chairman Murkowski, Ranking Member Cantwell, Committee members. Thank you for the opportunity to provide this testimony in support of a national effort to enhance our nation's energy infrastructure.

I'm John Di Stasio. I'm the President of the Large Public Power Council (LPPC). We represent 26 of the largest municipal utilities across the country serving over 30 million consumers in 13 states.

We are significant infrastructure investors, owners and operators. Together, we own about 70,000 megawatts of generation and approximately 90 percent of all the public, non-federal transmission in the United States. We also belong to the American Public Power Association who has some 2,000 utilities in 49 states across the country.

This morning I'd like to speak to the importance of investment in new electric infrastructure, the role public power plays in the electric grid and our interest in partnering with the Federal Government. I'd also like to share my thinking on how certain barriers to investment might be addressed and the important role played by the federal Power Marketing Administrations, or the PMAs.

First, the nation's electric infrastructure, it is reliable as was mentioned, but it does face significant challenges. There's much we need to do to modernize certain aspects of the grid and to address emerging risks.

While average nationwide annual loads have been relatively flat or even declined in some cases, the need for new transmission infrastructure is driven by changing resource mixes and also opportunities to improve reliability and resilience.

In addition to investment in large-scale transmission projects, the industry is investing substantially in smartgrid technologies aimed at optimizing the grid. These investments incorporate a range of technologies to facilitate such things as improved transparency for consumers, driving better energy choices, energy efficiency, grid situational awareness, the integration of distributed energy resources, electric transportation and also a big focus on cybersecurity. These are all areas of opportunity and need, and we look forward to assisting based on the lessons learned today.

Second, LPPC supports the role for the Federal Government in partnering to build infrastructure, and we urge you to work with public power. Over the last decade, public power utilities have invested more than $100 billion in infrastructure to serve our communities.

There's merit in the idea for partnerships between the government and non-federal entities. My own experience speaks from the time I spent as the CEO of the Sacramento Municipal Utility District, affectionately called SMUD. We implemented a $127.5 million grant from the Department of Energy, added $180 million of matching funds and did a very, very substantial smartgrid investment grant project that, I think, is paying dividends even today. I believe this experience is a useful model for a federal municipal partnership.

Third, LPPC believes that the exercise of federal authority over electric transmission siting can be improved. As was mentioned before, transmission is a necessary element, but it involves multiple agencies and we've been supportive of a federal role and assisting in that process. Some of the things that were outlined in your proposal go a long ways toward improving some of the timelines and the risk of those projects.

We also see room for improvement in the hydroelectric relicensing project. And I know you've also addressed this. Hydropower is economical, renewable and carbon free, yet the licensing process governing the development of new facilities and relicensing of existing plants is lengthy.

Again, my own experience while at SMUD was that our 12-year relicensing process for our hydro facilities was typical, if not better than most. We support initiatives such as those advanced by this Committee to reform that process.

Finally, LPPC urges Congress to be respectful of the role played by the federal Power Marketing Administrations. We strongly urge the Committee to reject proposals now circulating that call for the sale of transmission assets owned by federal PMAs to private entities. Each of the PMAs provide critical service to members of the public power community and none are a drain on the Treasury since we provide the investment and support for those facilities, paid for through the electric rates. These entities are responsible for administering federal energy infrastructure vital to the regions they serve.

To conclude, we're very supportive of an increased focus on the nation's infrastructure and stand ready to be a resource and a partner to this Committee and Congress.

Thank you.

[The prepared statement of Mr. Di Stasio follows:]

Testimony of
JOHN DI STASIO, PRESIDENT,
LARGE PUBLIC POWER COUNCIL

Before the
UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

Hearing to Examine the Evolution of Energy Infrastructure in the United States and How Lessons Learned from the Past Can Inform Future Opportunities

February 8, 2018

CELEBRATING
30 YEARS
LPPC
LARGE PUBLIC POWER COUNCIL

Testimony of John Di Stasio
President, Large Public Power Council
February 8, 2018

Introduction

Chairman Murkowski, Ranking Member Cantwell and Members of the Committee, thank you for the opportunity to testify in support of a concerted national effort to enhance our nation's infrastructure. My name is John Di Stasio, President of the Large Public Power Council (LPPC). I appreciate your focus on the nation's energy infrastructure and the crucial role that it plays. The points I will emphasize today are these:

- The nation's electric infrastructure is robust, but opportunities for modernization and the need to address emerging risks call for new investment.
- Public power utilities play an important role in the nation's electric grid and in the regions and communities that they serve.
- There is a role for the federal government in partnering with non-federal utilities, including those in public power. Federal funding should be focused on advancing goals and outcomes, and allowing for regional, state and local solutions.
- Federal siting and licensing processes can be improved.
- Certain barriers to state and municipal utility participation in an electric infrastructure initiative should be reduced or eliminated.
- Investment incentives should empower utilities to make prudent investment decisions based on their experience.
- The role played by federally-owned utilities should be respected.

Testimony

1. The Nation's Electric Infrastructure Is Robust, But Opportunities for Modernization and The Need to Address Emerging Risks Call for New Investment.

The electric power sector comprises an enormous and critical component of the nation's economic infrastructure. It serves as a building block for every sector of the nation's economy. The component parts of the electric sector include distribution, transmission and generation subsectors. The distribution sector is generally subject to state and locally-based oversight and the transmission and generation sectors subject to a combination of federal, state and local regulation.

The electric grid is reliable by any measure but faces significant challenges. While average nationwide annual load has been relatively flat and has even declined in some regions, the need for new transmission infrastructure investment is being driven by a changing generation resource mix, reflecting the retirement and anticipated retirement of some large coal and nuclear fueled generating stations and a shift to renewable, natural gas-fired and distributed energy resources.

In its 2017 Long-Term Reliability Assessment, the North American Electric Reliability Corporation (NERC) reported that a total of 6,200 miles of transmission additions is currently planned in order to meet these evolving needs, with 1,100 circuit miles of transmission currently under construction.[1] NERC further reports that while much of this investment is in regions that have experienced substantial growth in renewable generation, 78% of the investment is attributable to reliability needs and 13% of it specifically to the integration of variable renewable generation.[2] By rough order of magnitude, these plans represent an incremental investment in the grid of well over $20 billion annually over the next several years.[3]

In addition to investment in large-scale transmission projects, the industry is investing substantially in "smart grid' technologies aimed at optimizing grid utilization. These investments incorporate a range of technologies that facilitate such things as: (1) improved information to increase customer energy choices and more efficient energy use (e.g. smart meters, smart thermostats and home and mobile energy displays); (2) equipment enhancing grid situational awareness; (3) equipment enhancing the integration of distributed energy resources; (4) Investment in transportation electrification; and (5) investment in cybersecurity.

2. Public Power Utilities Play an Important Role in the Nation's Electric Grid and in the Communities They Serve.

Public power utilities are a large, integrated component of the nation's electric grid. LPPC represents 26 of the nation's largest public power systems, which provide power to over 30 million people in 13 states. These utilities are owned by and accountable to the state and municipal governments to whose communities, citizens and businesses they provide service. Together, LPPC member utilities own more than 71,000 megawatts of generation capacity powered by natural gas, nuclear, coal, hydroelectric, wind, solar and other renewable energy sources. LPPC members own and operate roughly 90% of non-federal, public agency owned transmission in the United States.

LPPC members are also members of the American Public Power Association (APPA), the umbrella organization which represents 2,011 public power utilities, providing electricity to 49 million people in every state but Hawaii. LPPC members are the larger members of this community, owning the bulk of public power's transmission and generating assets. Nationwide, public power entities own 10% of the nation's electric generating fleet, 10% of its transmission and 15% of the electric distribution grid. These systems are an integral, reliable and economical part of the nation's energy grid.

The hallmark of all public power entities is their commitment to public service and the communities they serve. These are community-owned enterprises whose only mission is to provide service to their cities, states and communities. Public power utilities employ 93,000

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[1] *See:* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf, p. 32-22.
[2] *Id.*
[3] *See* http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf

people and return, on average, 5.6% of their operating revenues to their communities through payments, fund transfers or reduced fees for service.[4]

3. There Is a Role for The Federal Government in Partnering with Non-Federal Utilities, Including Those in Public Power.

LPPC strongly supports a role for the federal government in facilitating grid modernization and resilience. There is merit in the proposals for partnerships between the government and non-federal entities, provided that these partnerships include public power utilities. Over the last decade, public power utilities have invested more than $100 billion in power distribution, transmission, and generation equipment needed to support reliability, affordability, environmental stewardship and economic development in the regions and communities that we serve.

My own experience directly speaks to the value of these partnerships. When I was the CEO of Sacramento Municipal Utility District (SMUD), SMUD implemented a $127.5 million grant from the Department of Energy (DOE) and added $150 million in matching funds to implement grid modernization in 2011-2013. This investment enabled us to improve reliability, resilience, cyber security, improve energy usage and consumption patterns dramatically, while integrating emerging technologies. It was truly an effort to transform our distribution grid from electron delivery to an interoperable platform. The experience is a model for a federal municipal partnership that we can continue to use successfully.

SMUD's experience underscores that federal partnerships aimed at increasing infrastructure development must include publicly owned and privately- owned entities. Community-owned utilities are an integral, reliable and technically forward-looking part of the electric grid, and every bit as capable of leveraging federal funds as are private entities, if some of the barriers to investment describe below are addressed.

4. Clearing Away Barriers to Infrastructure Investment.

It is important to address three barriers to government investment in electric infrastructure investment based upon our experience. The first and second, related to siting authority for facilities on federal lands and hydroelectric licensing – are common to public and private utilities alike. The third is unique to financing arrangements employed by the public power utility community for which I speak.

a. Federal Authority Over Electric Transmission Siting Can Be Improved

Larger, long-line transmission facilities linking significant markets with remote sources of generation will often cross several states and involve federal lands, thus implicating siting authority of multiple states, some localities and federal agencies. Coordination among these varied authorities can difficult, expensive and time-consuming.

[4] *See:* https://www.publicpower.org/public-power/stats-and-facts

As to relevant federal agencies, previous administrations have made well-intentioned efforts to improve their coordination; however, the process remains complicated, lengthy and often focused on individual agency objectives, as opposed to the overarching project objectives. Federal and state agency coordination is often lacking and conducted in a serial fashion adding significant time and cost barriers to any project. We fully support the necessary review at all jurisdictional levels to determine public purpose, economic and environmental impact. With that said, efforts to streamline these processes would remove significant project risk and cost. We appreciate your focus on this important aspect of infrastructure development.

b. The Hydroelectric Licensing Process Can Be Improved

Hydropower is a remarkably economical, renewable and carbon free resource, and yet the licensing process governing the development of new facilities and the relicensing of existing plants is enormously time-consuming, expensive, and inefficient. This process is lengthy and costly. My own experience while at SMUD was that a 12-year relicensing process for our hydroelectric facilities was typical, if not a bit better, than the relicensing time lines experienced by others. The licensing process typically involves several federal and state resource agencies, and often these agencies appear indifferent to the societal benefits of provided by hydropower.

With all due respect for the missions of each of these agencies, I believe we can do better in managing their input, and the resulting process at FERC, given the large economic and environmental stakes associated with the retention and addition of hydropower resources. For this reason, I support initiatives such as those advanced by this Committee to reform this process.

c. Financing Has Been a Barrier

There are two potential obstacles to community-owned utility participation in a federal infrastructure initiative, both related to the financing tools employed by the public power community, that we ask for the Committee to work with colleagues to address: that comparable incentives be considered for the public power community, and secondly, reform of Internal Revenue Service (IRS) regulations that may stand in the way of municipal participation in federal/non-federal partnerships.

On the first point, since public power utilities are not subject to federal taxation and rely upon tax exempt municipal bonds for their larger investments, it is critical that any federal incentives in support of infrastructure provide a mechanism, such as direct pay bonds, refundable tax credits or grants that can also be accessed by non-tax paying entities. These federal incentives can significantly accelerate, or leverage infrastructure investments already planned or contemplated.

Our experience with the American Recovery and Reinvestment Act funding was mixed. The "Build America Bonds" (BABS) were a very good mechanism to provide additional financial assistance to State and local governments and broaden the investor pool, but they were subject to sequestration after the fact, significantly lessening the benefit and creating concern for the use of this type of "direct payment" bond in the future. The DOE Smart Grid grants were put to good use by SMUD, as well as many public and private utilities across the country. As currently written, incentives offered in the form of tax credits are not accessible to public power without engaging a tax paying counter party, again creating inefficiencies that significantly lessen the benefit that accrues directly to consumers, and in some cases, limits the size of the investment.

Second, many of the IRS private use restrictions have not been updated since the 1986 and may need to be modified to facilitate certain public private partnerships and to enable public power to operate effectively in the current industry environment. IRS regulations restrict the use of funds derived from tax-exempt financing to projects that are devoted to public, not private, purposes. The application of these regulations is complicated in connection with electric grid facilities that can serve private and public purposes.

5. Experience Suggests that Infrastructure Investment Objectives Should Focus on Outcomes

As Congress may consider policies to spur investment in the grid, I urge policy-makers to avoid prescriptive solutions, recognizing that the electric industry performs best when asked to meet broad objectives, thus empowering the industry to determine how best to meet public policy goals based on regional differences, existing infrastructure and state policy objectives. Put another way, the industry responds best when directed to address "the what" and not "the how."

This approach is relevant to two issues that may arise in connection with federal support for infrastructure investment. The first involves federal support for grid modernization. Any funds that are made available steer clear of prescriptive solutions. Broad objectives that come to mind are efficiency in energy usage, grid resilience/reliability and cost reduction. More specific directives would thwart broader goals by preventing utilities the flexibility to achieve national objectives.

Closely related are efforts to improve grid resilience. This topic has been in the headlines, in substantial part due to legitimate interest in strengthening the grid in response to recent disasters. These efforts have also attracted attention due to DOE's Notice of Proposed Rulemaking in Docket No. RM18-1. In that docket, DOE proposed that FERC establish a funding mechanism aimed at supporting electric generation with 90-day fuel supply, a category that is effectively limited to coal and nuclear resources. The effort drew fire for the attention it narrowly focused on specific generating resources and was recently rejected.

While the DOE NOPR launched a productive conversation regarding system resilience, its emphasis on a single solution would have foreclosed discussion of the range of resources and techniques that support grid resilience. These attributes can be exhibited by a variety of generating resources. Federal policy should be performance-based and technology-neutral, permitting a variety of investment choices meeting objective goals. I urge the Committee to keep this lesson in mind as it considers various ways to target infrastructure investment.

6. State and Locally-Based Solutions and Objectives Must Be Respected.

As support for investment in nation's electric infrastructure is considered, I urge the Committee to be respectful of state and locally-based policy objectives, including varied environmental goals. We believe such deference is hard-wired into our federal system, and particularly important to preserve harmony in an environment in which we do not have national consensus on certain of these objectives. We can all agree that a reliable, resilient electric grid is a shared goal, but we obviously do not have consensus now on a variety of other policy goals, including those related to the environment. For this reason, LPPC urges Congress as it considers grid investments to allow states and local governments the space to accomplish additional policy objectives they consider important.

7. The Role Played by Federally-Owned Utilities Should be Respected.

Finally, LPPC strongly urges the Committee to reject proposals now circulating that call for the sale of transmission assets owned by federal Power Marketing Administrations (PMAs) to private entities. There are four PMAs in the nation, each of which provides critical service to members of the public power community, and none of which represents a drain on taxpayer resources. These entities are Bonneville Power Administration (BPA), Western Power Area Administration (WAPA), Southeastern Power Administration (SEPA) and Southwestern Power Administration (SWPA). Each are responsible for administering hydroelectric resources developed on federal waterways with the aim of serving local communities in their regions.

The PMAs are active and constructive participants in the power sector and serve a critical role in providing service to communities that need it. Federal law under which each of the PMAs operate require them to set rates at levels that ensure that the cost of all federal investment (plus interest) is recovered, and that taxpayers bear no cost responsibility for their operation. Rates collected by WAPA, SEPA and SWPA flow through the U.S. Treasury, and are designed never to result in funding shortfall. Though BPA funds are collected and spent directly by the PMA, the economic result is the same. For this reason, there is no argument that the PMAs are a burden on taxpayers.

I am aware that there are economic interests interested in "recycling" certain of the PMA assets to have the resources invested elsewhere. This would be a mistake. Selling the PMA assets would be a zero-sum game. The assets currently recover their full costs through rates, and no more. If there is some benefit associated with their sale, it would result in the purchasing entity charging more to generate a rate of return and likely eliminate the other economic and environmental objectives being achieved. The resulting economic harm would shift to the communities these assets were built to serve.

Conclusion

LPPC stands ready, based on its members' deep and diverse experience, to be a resource and partner to this Committee as Congress considers policies to advance federal and non-federal investment in infrastructure. We look forward to working with you to focus on the ways in which the government can work with public power as partners in improving the nation's electric infrastructure.

The CHAIRMAN. Thank you, Mr. Di Stasio.
Mr. Allen, welcome.

STATEMENT OF DAVID ALLEN, EXECUTIVE VICE PRESIDENT, McKINSTRY COMPANY

Mr. ALLEN. Well, good morning, Chairman Murkowski and Ranking Member Cantwell. We thank both of you for visiting McKinstry. We appreciate our elected officials coming out and seeing what happens on the ground in our companies.

I'm David Allen. I'm the Executive Vice President of McKinstry Company. Thank you for the invitation to speak. I've traveled a long way to get here and it is very important for me to be here.

I am here to share lessons we've learned from more than 50 years as a company designing, building, operating, maintaining and managing facilities across the United States. I represent about 2,000 employees of all levels: union workers, construction workers, engineers, marketing people, project managers and so on. We believe any responsible infrastructure legislation argued before Congress must: one, include funding to update our aging and failing power grid; two, prioritize conservation over consumption; and three, test market readiness through demonstration projects.

I assume the first point will be thoroughly discussed by my industry colleagues here that actually are, kind of, humbling for me since I, kind of, come from Main Street. Instead, I'll use my time to focus on some of the things that the Senators saw that we see in investing in energy efficiency.

We obviously favor conservation over consumption. The potential to make our built environment more energy efficient is virtually limitless.

Approximately 80 billion square feet of non-industrial facility space uses 70 percent of the electricity of the United States which is staggering, and which is more staggering is that we believe, and a lot of experts believe, that half of that energy from generation to consumption is wasted which probably could make energy efficiency one of the largest pools of renewable resources at the cheapest price to get of all the renewables out there.

To find an example of this opportunity we needn't look further than a local school district. K–12 schools are crippled with deferred maintenance and shrinking operational budgets. Energy efficiency projects are an attractive solution for many of our clients to upgrade critical health and life safety systems with little to no out-of-pocket funding.

Infrastructure needs are addressed in the short-term, and scarce operational dollars are freed up over the long-term, to continually fund competing needs like teacher salaries, class size reduction and STEM programming.

More broadly, a recent analysis by Oregon-based economists found that energy efficiency investments increase overall economic productivity across all sectors of our economy.

When you think about it, spending money on wasted energy is about the least productive thing we can do as a society. Eliminating energy waste and freeing up that capital allows people to spend in ways that improve the underlying productivity of their economies.

We have enormous opportunities to gain productivity and efficiency with targeted approaches to public policy and funding that prioritizes conservation over consumption.

Smart and connected communities are the future. There's no debate about that. The world is heading that way, and the United States is heading that way.

We encourage this Committee to continue to inspire innovation by funding demonstration projects. The lessons we learn from these demonstration projects have been the foundation for the next wave of innovation. In fact, Phil mentioned a couple of them.

There are two areas of these demonstration projects we encourage the Committee to get more familiar with.

One, invest in rural, hard-to-reach communities. Energy costs are disproportionately high in many corners of our country where the centralized grid has limited reach. We must be open to new technologies and approaches to securing a reliable and cost-effective energy future.

As an example, which is incredible, Costa Rica has been 100 percent off grid using renewable energy, energy-efficient technology and battery storage to meet their needs for almost one full year, which could be a metaphor for our smaller communities across the country. We urge the Committee to bring to market these off-the-shelf technologies across rural America through these demonstration projects. No community should be left behind as we upgrade our energy infrastructure, and the best ideas should be encouraged to surface.

Finally, tailor funding and legislation to fuel the shared economy through ECO district systems as a federal demonstration project. An ECO district arrangement is one where one entity's waste heat becomes another entity's fuel source. ECO district demonstration projects have the potential to significantly shift the utility infrastructure paradigm driving waste out of our built environment and ultimately increases economic productivity for all. In addition, ECO districts interconnect smart buildings and smart systems—exploding the need for the Internet of Things, which is upon us right now, and American invention of new technology.

We have the responsibility to think differently about the development of our cities and incite exploration of shared infrastructure that requires multi-party cooperation for the good.

Thank you for the opportunity to share, and I'd be happy to answer questions down the road.

Thank you.

[The prepared statement of Mr. Allen follows:]

Testimony of David Allen, Executive Vice President, McKinstry Company

Before the Senate Committee on Energy and Natural Resources

February 8, 2018

INTRODUCTION

Good morning Chairman Murkowski, Ranking Member Cantwell, and other members of the committee. I am David Allen, Executive Vice President of McKinstry. Chairman, you met my brother Dean last summer at McKinstry while touring through Seattle; he sends his regards.

Thank you for the invitation to speak with you today about energy infrastructure.

I am here to share the lessons we've learned from more than 50 years of designing, building, operating, maintaining, and managing facilities across the United States. I represent the 2,000 men and women who work for McKinstry, made up of sheet metal works, plumbers, pipefitters, service technicians, accountants, energy engineers, construction managers, commissioning agents, data analysts, and more. This diverse set of crafts and skills have a common denominator - invention. No two buildings are alike, which requires an inventive culture to meet the evolving financial and operational needs of our clients.

This is a cornerstone to our growing energy efficiency practice, where we are called upon by cities, counties, states, hospitals, schools, campuses, and corporations to help manage their energy footprint. Often, we analyze current energy use and offer recommendations for improvement, other times we are solving age-old problems with new technology.

We needn't look further than a local school district for opportunity. K-12 schools are crippled with deferred maintenance and shrinking operational budgets in nearly every community across America. Energy efficiency projects are an attractive solution for many of our clients because health and life safety systems, so critical to classroom learning, are upgraded or optimized with little-to-no out-of-pocket funding. Infrastructure needs are addressed in the short term, and scarce operating dollars are freed up in the long-term to fund competing needs like teacher salaries, class-size reduction, or STEM programing.

I'm sure Senator Cantwell has said more than once before this committee, "if it can work in Washington State, where power is cheap and abundant, it really can work anywhere." And she is right.

Investing in approaches and technologies that make local communities more resilient, efficient, and productive should be the goal we all work toward together, across the aisle. Any responsible infrastructure legislation argued before congress must include funding to update our aging and failing power grid, prioritize conservation over consumption, and test market readiness through demonstration projects.

I assume the first point – that we must update our aging and failing grid -- will be thoroughly discussed by my industry colleagues today. Instead, I will use this time to focus on the two remaining areas for investment.

CONSERVATION OVER CONSUMPTION

The potential to make our built environment more energy efficient is virtually limitless. Approximately 80 billion square feet of non-industrial facility space uses 70% of the electricity in the United States. We believe half of that energy—from generation to consumption--is wasted.

A recent analysis by Portland, Oregon based economists at ECONorthwest, found that energy efficiency investments increase overall economic productivity across all sectors of the economy. Of course, reducing energy waste provides immediate benefit to homeowners, schools, hospitals and businesses as they save money on their energy bills, but these economists were interested in what happens when those saved dollars are otherwise spent by end-use customers. ECONorthwest found a significant macroeconomic effect from that spending that reverberates across the economy.

When you think about it, spending money on wasted energy is about the least productive thing we can do with society's capital. Eliminating energy waste, and freeing up that capital, allows people to spend in ways that improve the underlying productivity of the economy. In aggregate, this means more money for business expansion and job growth. Using sophisticated macroeconomic models and actual economic performance data from the states of Washington and Oregon, the analysis concluded that energy efficiency investments increase economic growth, increase job creation - and not just in the clean energy sector, but across all sectors of the economy -- and reduces income inequality.

We have enormous opportunities to gain productivity and efficiency with targeted and thoughtful approaches to public policy and funding that prioritizes conservation over consumption.

SMART AND CONNECTED COMMUNITIES

All of us in this room understand the magnitude of the energy grid problem. But it is precisely because of the magnitude that we often lose our ability to see how individuals can play a role in the solution. I encourage this committee to continue the precedent of inspiring innovation at the community level by sending clear market signals and funding them through demonstration projects.

The Northwest has been the beneficiary of previous demonstration investment. I can speak to the direct impact this has had on our business, and the communities where we work and live. The small energy management team we built up to support the smart-grid demonstration project five years ago is a tangible example of this. Fast-forward to today and that team has tripled in size and grown to become an integral part of McKinstry's future. That demonstration project, stemming from discussions such as this, catalyzed a unique partnership that would have been difficult to assemble otherwise. Working alongside utilities, national labs, research universities, startups and established technology companies, we moved smart grid from theoretical to proven. Now there are still many miles to go on this smart-grid journey, but it's important to recognize that out of this effort, and others like it, new companies were born, new products launched, and new engineered solutions were devised to address long standing problems. The lessons we learned from the smart-grid demonstration project have become the foundation for the next wave of innovation.

There are two areas of demonstration that we encourage this committee to consider:

1. Invest in rural, hard to reach communities. Energy costs are disproportionately high and fluctuate radically in many corners of our country where the centralized grid has limited reach. The challenges facing these communities are entirely different than those of urban environments. We must be open to new technologies and approaches to securing a reliable and cost-effective energy future. As an example, Costa Rica has been 100% off grid, using renewable energy, energy-efficient technology, and battery storage to meet their needs for almost a full year. We urge the committee to activate market receptivity of these off-the-shelf technologies across rural America through demonstration projects. No community should be left behind as we upgrade our energy infrastructure, and the best ideas should be encouraged to surface.

2. Tailor funding and legislation to fuel the shared energy economy through ECO district systems as federal demonstration projects. As mentioned previously, the most inefficient use of capital is energy waste, which usually comes in the form of waste heat. In an ECO district arrangement, one entity's waste heat becomes another entity's fuel source. We have a proven example of this in downtown Seattle. ECO district demonstration projects have the potential to significantly shift the utility

infrastructure paradigm, driving waste out of our built environment and ultimately increasing economic productivity. In addition, ECO districts interconnect smart buildings and smart systems - exploding the need for IoT, and American invention of new technology.

We have a responsibility to think differently about the development of our cities and incite exploration of shared infrastructure that requires multi-party cooperation for the greater good.

CONCLUSION

Thank you for the opportunity to discuss our thoughts on where investment in the energy economy is needed. I would be happy to answer any questions you may have.

The CHAIRMAN. Thank you, Mr. Allen.

Dr. Medlock, welcome.

STATEMENT OF DR. KENNETH B. MEDLOCK III, JAMES A. BAKER, III, AND SUSAN G. BAKER FELLOW IN ENERGY AND RESOURCE ECONOMICS, AND SENIOR DIRECTOR, CENTER FOR ENERGY STUDIES, JAMES A. BAKER III INSTITUTE FOR PUBLIC POLICY, RICE UNIVERSITY

Dr. MEDLOCK. Thank you, Senator Murkowski, Senator Cantwell.

My written testimony lays out a basic framework for understanding the role that infrastructure plays in market function, price formation, the facilitation of innovation. I want to focus on a few very specific aspects of that. I'm actually encouraged to hear the testimonies so far because they tie very closely into what I'm going to say, and I'm sure Don's testimony will do the same.

A lot of times when we talk about infrastructure, we—and I think this has, kind of, played out so far—we tend to focus on infrastructure for delivery, infrastructure to facilitate end use through the application of new technologies and energy efficiencies, but oftentimes we leave out the most important part of actually leading to all of that which is the energy development phase. And this extends to all aspects of the energy spectrum—oil and gas, coal, wind, solar—all of these things, if we're going to use them, require infrastructure investment up front at the very upstream tail of the investment life of the entire energy cycle. So when we think about the role that infrastructure plays in facilitating market function and price formation, we have to really think about the entire value and that's something that cannot be lost.

When we talk about connecting markets, connecting consumers and producers to one another, that's really the most vital function we often think about as infrastructure playing. We've heard that with regard to transmission and power. We've seen a great example of where infrastructure is facilitated, a virtual explosion of wind capacity in the State of Texas, for example. The State of Texas, as you likely know, has more wind capacity than any other state in the country. And you might ask the question, well, why is that?

Well, first of all, there's a fantastic wind resource in the State of Texas. So that coupled with policies have actually helped propel the expansion of wind capacity generation assets in the state. But there was a potential stopping point. Namely, there was limited ability to move the power that's generated from that wind capacity to the place where people live which is in the eastern and southeastern part of the state. There was roughly $7 billion of infrastructure investment made to build power lines to connect those assets to the place where consumers were demanding them.

This also gets to another very important point which is the role of market structure and facilitating infrastructure investment. One of the things that's actually occurred in the State of Texas is the introduction of competition at the wholesale and retail levels in power markets. And you might say, well, what implication does that have for infrastructure?

Well, on the retail end, when you introduce competition providers all of a sudden had to differentiate themselves to capture market. In doing so they were able to capitalize on something called revealed consumer preference. This is the notion that some consumers might actually want to have a higher portfolio of renewable energy in their energy mix, so providers could actually market that. As that occurred it sent a demand signal that as long as there's infrastructure in place, works its way all the way back through the value chain to the upstream and that creates demand pull for new types of assets.

The same thing can be said, actually, of energy efficiency investments. The reference was made to Harvey, which was a fantastic reference by the way, and we've talked about this in Houston quite a bit. But the simple fact that when you compare the reality in the wake of Harvey to the reality in the wake of Hurricane Rita, for example, when it hit the region, power outages were much shorter in duration and it had a lot to do with the fact that smart technologies enabled Center Point to identify locations very quickly and dispatch crews much more efficiently to address issues.

These types of infrastructure investments effectively make the system that we're talking about much more resilient. That's something that, I think, cannot be underappreciated because as we move forward we really have to think about resilience, particularly in the broader context of energy security.

This gets into a host of other things that are actually addressed in my written testimony that relate to reliability and the role that infrastructure actually plays in maintaining reliability to end users.

At the end of the day, that's actually why we're here talking about this stuff. It's because constituencies around the country are concerned about access to energy.

The market has done a fantastic job in this country of ensuring, to date, that electricity reaches consumers reliably, that natural gas reaches power generation stations and industrial users and homeowners reliably, and that really is a function of market structure and regulatory institutions that make this country unique in many ways, very different from most other countries around the world. And it's something that really does lend itself to a competitive advantage for the United States overall.

Thank you. I'll be happy to address any questions.

[The prepared statement of Dr. Medlock follows:]

JAMES A. BAKER III
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Testimony of
Kenneth B. Medlock III
James A. Baker, III, and Susan G. Baker Fellow in Energy and Resource Economics, and
Senior Director, Center for Energy Studies
James A. Baker III Institute for Public Policy
Rice University

To the
Senate Committee on Energy and Natural Resources
Washington, D.C.

Hearing on
The Evolution of Energy Infrastructure in the United States and
How Lessons Learned from the Past Can Inform Future Opportunities

February 8, 2018

Infrastructure is vital for well-functioning markets. It plays a critical role in connecting supplies with demands, and is the architecture through which price carries signals to producers and consumers. Indeed, if deep, well-functioning markets are desired, then sufficient infrastructure is critical. For investments to occur in developing new supplies, access to infrastructure to connect producers to consumers is vital. In fact, this establishes the physical connection that leads to greater market depth and liquidity, which is important for energy security. The absence of sufficient infrastructure can disrupt investment and have bearing on whether there is adequate and reliable supply available to end-users.

This paper discusses the central role that infrastructure plays in price formation and touches on the additional impacts it has on foreign policy and US projection in diplomatic discussions. In addition, the interrelated nature of energy infrastructure with regulatory and legal frameworks establish the rubrics that govern the behaviors of market participants. To be clear, this brief testimony is not meant to be exhaustive, but it will highlight some key points that must be brought forth in any policy discussion related to energy infrastructure.

Altogether, the aim here is to highlight some critical discussion points when considering the role of policy for infrastructure. There are no explicit policy recommendations herein, as there are other issues beyond the scope of this discussion; rather, there are frameworks that must be used to analyze various pathways under consideration. Insufficient infrastructure in the energy domain can present a barrier to investment and growth, largely because commercial returns are unattainable. This, in turn, impacts producers *and* consumers, carrying implications for price and more broadly, energy security.

Energy Security, Trade and the Role of Infrastructure

Energy security generally refers to the concept of ensuring adequate supplies of energy at a reasonable price to avoid the economic dislocations and negative welfare impacts associated with energy price spikes or supply disruptions. So, while economic security is a broader concept that pertains to more than just energy, the concepts of energy security and economic well-being are intimately linked, as the former, if achieved, conveys elements of the latter. If infrastructure is not adequate, then energy security can be compromised and economic activity can be negatively impacted. In fact, infrastructure is critical to realizing the full slate of benefits associated with all forms of energy.

In general, there are several types of policies that can contribute to enhanced energy security. These include:

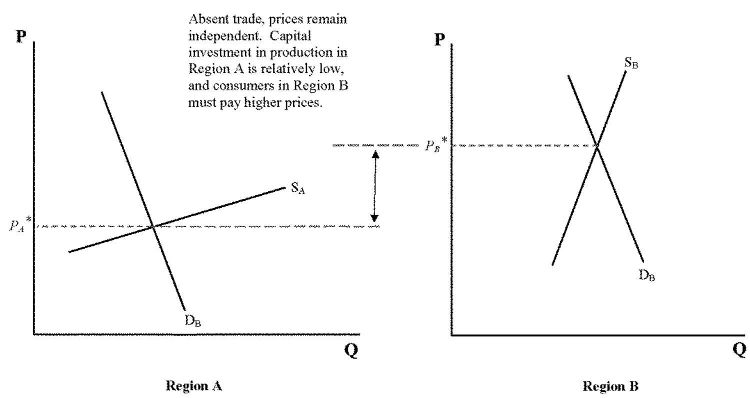
- increase energy efficiency in effort to lower the energy intensity of economic activity and thereby lower the expenditure share of energy;
- diversify the energy mix – through geographic dispersion of trading partners or through different types of resources – to lower the overall impact of disruptions in the supply of any one energy source;
- build inventory response capability (i.e. – storage) to offset the price implications of short term demand spikes or supply disruptions; and
- promote deeper, more liquid markets to provide greater opportunities to trade thereby reducing the impact of unexpected market disturbances on the supply portfolio.

Each of these has relevance to the realization of North American energy security and economic well-being. Moreover, each also indicates a distinct role for infrastructure in facilitating competition and trade. For example, energy efficiency can be enhanced through infrastructure investments in "smart" technologies by electricity consumers. Such technologies can convey real time pricing data to consumers thereby allowing them to adjust consumption patterns in response. When this occurs, it can reduce overall electric system load and allow existing generation resources to operate in ranges that maximize system redundancy and reliability.

Similarly, diversification in the energy mix can be achieved through infrastructure investments that allow substitution of energy sources seamlessly. Wholesale electric power markets have been doing this for years, but the introduction of distributed generation infrastructures have the potential to be disruptive to the status quo while adding another element of diversification to the overall grid. Managing such a turn is, of course, paramount, and it will carry repercussions for other types of infrastructures related to the provision of energy services.

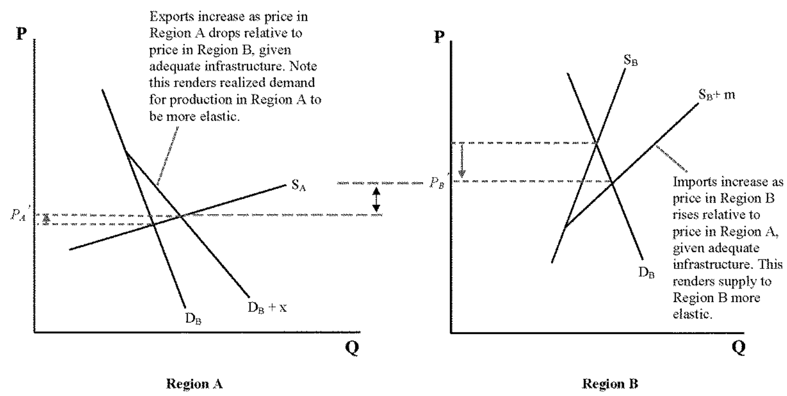
The latter two bullets relate to intertemporal trade (via storage) and spatial trade (via pipelines, wires, tankers, etc.), respectively. In both cases, the existence of infrastructure that allows trade to occur enhances market function and adds elements of reliability and security of supply for consumers. A simple illustration rooted in trade theory can be useful to demonstrate the role that trade facilitated by infrastructure can play. Consider two regions that could be connected by infrastructure to facilitate trade, but initially are not. In Region A, there is an abundance of available supply relative to demand. In Region B, there is less supply available relative to demand. As indicated in Figure 1, absent the ability to trade, prices across the regions will be set independently, and markets will balance at the indicated prices, P_A^* and P_B^*.

Figure 1 – Two regions: No infrastructure and no trade



However, as indicated in Figure 2, if we introduce the physical ability to arbitrage the price differences between Regions A and B, the prices in each region will be set simultaneously, rather than independently and the markets will clear at P_A' and P_B', where the difference between prices reflects the cost of transport between the two regions. Notably, when infrastructure does not exist, the effective cost of trade (shadow cost) is infinite, so prices in the two regions can float within a very wide range of each other. The same thing is true if capacity (infrastructure) is limited and insufficient. If capital is mobile, when trade via new or expanded infrastructure is introduced we will see investments flow into Region A to facilitate greater production. We will also see investments flow into Region B to accommodate greater demands that lower prices incentivize. The exact movements of prices in each region will depend on the relative elasticities (price responsiveness) of supply and demand in each region, which will also determine the amount of trade that occurs (and infrastructure that is required).

Figure 2 – Two regions: Adequate infrastructure and trade

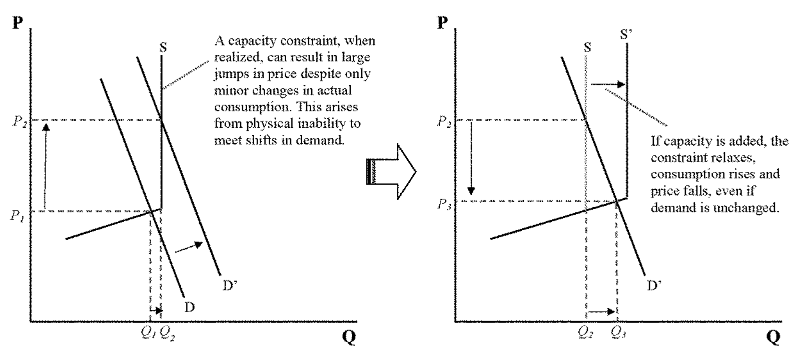


To stop here does not fully explain the value of infrastructure for price formation between the two regions. Notice, in Figure 2, how the elasticities (slopes) of supply in Region B and demand in Region A are affected when there are no impediments to trade. This conveys a very important point. Namely, physical infrastructure enhances market fungibility across regions. If we allow demand to vary seasonally, as is generally the case for energy, the volatility of price is dampened, all else equal, when trade is allowed. As a case in point, we can consider regional natural gas prices – internationally and domestically. Constraints on the ability to meet the unexpected demand shock in the wake of the disaster at Fukushima resulted in the spot price of Asian LNG rising to unprecedented levels. If LNG export capacity had existed in the US at that time, price would not have risen to the levels witnessed. In fact, the rush to seek permits for export facilities in the years that followed indicated a desire by investors to capture the arbitrage opportunity – through infrastructure development – that arose between the US and Asia.

This phenomenon is not unprecedented, nor is it unique to Asian LNG pricing. We have seen similar circumstances in the continental North American market when extreme cold grips certain regions and drives up local demand in excess of what existing pipeline capacity can deliver. For example, an extreme cold weather event in the Northeast has been known to trigger the daily price in Boston (at Algonquin City Gate and TGP Zone 6) to jump more than $70 per thousand cubic feet above the price at Henry Hub because pipeline capacity is not sufficient to meet the sudden surge in regional demand. This is often referred to as a "basis blowout" and is driven by a realized capacity constraint on the ability to deliver supply. Fortunately for consumers in the affected regions, these price shocks are generally short-lived, subsiding when the cold weather event passes. Moreover, the depth of the US market provides substantial liquidity through which price differences are quickly arbitraged as the supply constraint is relaxed.

This raises a very important point about the role of adequate infrastructure for price formation. When infrastructure is insufficient, short term movements in supply and demand can result in significant price dislocations. Consider, for example, Figure 3. Here, we see a region that initially has sufficient capacity to deliver energy for a given demand schedule, then a shift in demand results in the existing infrastructure being insufficient to meet new demands (see Step 1 in Figure 3). The result of the realization of a constraint on the ability to physically deliver supply to the market is a significant increase in price even though actual consumption may not rise very much. Notably, if demand swings due to seasonal factors, this can result in excessive price volatility as the constraint is realized and relaxed over and over again.

Figure 3 – The Role of Capacity Constraints in Price Formation



Step 1 – Inadequate infrastructure renders constraint

Step 2 – New infrastructure relieves constraint

However, if we add delivery capability to the market, the constraint is relaxed, even at the higher level of demand, and price falls despite actual consumption rising (see Step 2 in Figure 3). In both cases (Steps 1 and 2 depicted in Figure 3), the market clears where available supply equals demand, resulting in a market clearing price and quantity consumed. But, in the case where the deliverability (supply) constraint is relaxed, price is lower, greater consumption is facilitated and price volatility is dampened.[1]

Returning to the example of LNG pricing in Asia, the post-Fukushima price increase did not abate quickly unlike the aforementioned basis blowouts associated with weather-driven demand shocks. But, as new sources of LNG supply have been brought online (Papua New Guinea, East Australia, and others) and demand has been rationalized by price, the binding deliverability constraint to the Asian market has been relaxed (as in Step 2 in Figure 3) and the spot price of LNG has settled back into a range that is more consistent with a globally arbitraged price. While there may eventually be short term constraints that result in temporarily elevated LNG prices, if infrastructure continues to expand, the long term will be characterized by deeper, more fungible markets in which regional prices communicate unimpeded. This is where it becomes important to more generally consider what increased trade in the global LNG market will do to the nature of pricing abroad. Of course, greater LNG trade requires sufficient infrastructure throughout the value chain – in field production, pipelines, liquefaction, shipping and regasification – but as more players enter the market, competitive pressures will mount regardless of the source of LNG. As US LNG exports in particular rise, the global market will become physically linked to North America, the most liquid natural gas market on the world. This should, in turn, facilitate more trade and alter the liquidity paradigm that has characterized the global LNG market heretofore. The credible threat that US LNG serves to incumbent regional suppliers – Russia into Europe, for example – coupled with greater market liquidity will fundamentally alter the nature of natural gas pricing everywhere. Infrastructure is critical to such an outcome.

Infrastructure and the Current US Energy Renaissance

During the past 15 years, innovative new techniques involving horizontal drilling and hydraulic fracturing have unlocked a vast resource potential and resulted in the rapid growth in production of natural gas from shale. The same techniques have also matriculated into the oil sector resulting in a dramatic increase in light tight oil production. Oft underappreciated facets of the so-called "shale revolution" are the regulatory features and market institutions that facilitated the rapid expansion of production in the US. In fact, as production has grown, US supply has become more price responsive, which, in turn, has contributed to greater energy security. This has been propelled by rapid deployment of capital throughout the energy value chain and the consequent development of production and distribution infrastructure.

So, what made the successes witnessed in the US during the past 15 years possible? To begin, geology matters. The scale of the technically and economically recoverable oil and gas resources

[1] "Deliverability constraints" refer to constraints on access to capacity, which can result if physical capacity is short or if capacity is rendered unavailable through other means. In any case, the result is an increase in price.

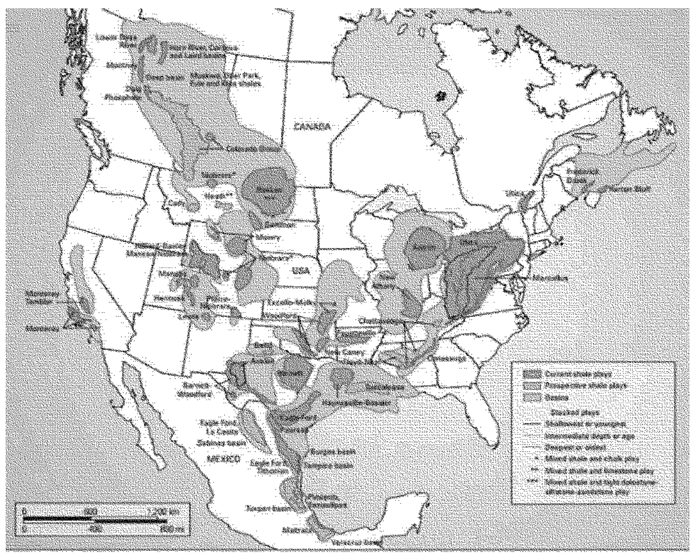
locked up in shale is tremendous and geographically diverse (see Figure 4), and as time passes the understanding of the resource expands. But, while the right geology is a *necessary* condition, it is not *sufficient*. Shale resources assessed in locations outside the US are significant, yet shale oil and gas production on a global scale is still largely limited to the US. This follows because *sufficiency* requires a host of above-ground factors to be appropriately aligned. These include market institutions and regulatory frameworks spanning the energy value chain, such as…

- a regulatory and legal apparatus in which upstream firms can negotiate directly with landowners for access to mineral rights on privately-owned lands.
- a market in which liquid pricing locations, or hubs, are easily accessed due to liberalized transportation services that dictate pipeline *capacity* is unbundled from pipeline *ownership*.
- a well-developed pipeline network that can facilitate new production volumes as they are brought online.
- a market in which interstate pipeline development is relatively seamless due to a well-established governing body – the Federal Energy Regulatory Commission (FERC) – and a comparatively straightforward regulatory approval process.
- a market in which demand pull is sufficient, and can materialize with minimal regulatory impediment, to provide the opportunity for new supplies to compete for market share in the energy complex.
- a market where a well-developed service sector already exists that can facilitate fast-paced drilling activity and provide rapid response to demands in the field.
- a service sector that must compete by reducing costs and improving technologies in order to gain a competitive advantage.
- a sizeable rig fleet that is capable of responding to upstream demands without constraint.
- a deep set of upstream actors that includes independent producers that can behave as the "entrepreneur" in the upstream thereby facilitating a flow of capital into the field toward smaller scale, riskier ventures than those typically engaged by vertically integrated majors.

Every one of the above bullets has some relevance to infrastructure – from permitting to access to market function to price formation to investment, etc. If any of these features is absent, an effective barrier to market development is presented, usually manifesting in the form of higher costs. Moreover, some of the above *sufficient* conditions can be co-dependent on the others, which highlights to the notion that well-designed market institutions and regulatory frameworks can be self-reinforcing. For example, a well-developed service sector relies on a deep set of entrepreneurial (independent) upstream players to create large demands for its products and services, just as the population of independent producers in the US upstream might not be so deep absent a well-developed service sector.

The coexistence of these factors makes the US a unique environment for upstream shale-directed investments. This, in turn, highlights the importance of each in achieving US energy-related geopolitical and foreign policy aims. More specifically, the legacy of domestic regulatory and market institutions engenders significant global influence, and infrastructure has played a central role in fostering the current reality.

Figure 4 – Shale Resources in North America



Source: http://alfin2300.blogspot.com/2012/03/gallery-of-world-hydrocarbon-endowment.html

Why does this matter?

There is much discussion about the US being an "energy superpower." In fact, this terminology has permeated the US State Department and been a recognized facet of diplomacy carried forth by the Bureau of Energy Resources for the past several years. Currently, we can see this directly from the Bureau of Energy Resources website.

> ENR promotes U.S. interests globally on critical issues such as: ensuring economic and energy security for the U.S. and our allies and partners; removing barriers to energy development and trade; and promoting U.S. best practices regarding transparency and good governance. In addition, we review applications for the construction, connection, operation, or maintenance of facilities for the exportation or importation of petroleum, petroleum products, coal, and other fuels (except for natural gas) at the borders of the United States.

> The Bureau serves as the principal advisor to the Secretary of State on energy security, policy, operations, and programs. Through diplomacy and a wide range of programs, ENR works to ensure worldwide energy security by fostering diverse global energy supplies from all sources of energy.
>
> ENR operates at the critical intersection between energy and U.S. national security, and ensures U.S. leadership on global energy issues. U.S. national security is threatened when:
>
> - Our allies lack reliable access to affordable energy or a diversity of choices;
> - Foreign energy markets shut out U.S. companies;
> - Poor governance prevents market-based energy solutions;
> - Competition for energy leads to conflict; or
> - Terrorists and rogue regimes seek to exploit energy resources to fund violence and destabilizing activities.
>
> To address these challenges, ENR works with leaders at the highest levels of government, business, and civil society, playing a crucial role in achieving U.S. foreign policy objectives in the energy arena. ENR foreign assistance programs are integral to the Bureau's diplomatic engagement overseas and provide critical support for the Department's objectives and the Administration's global diplomacy priorities.
>
> See: https://www.state.gov/e/enr/, accessed Feb 5, 2018

The emergence of the US as an oil and gas exporter has facilitated the goals set forth by the US State Department. So, the energy renaissance has had direct bearing on US diplomacy. However, the US government is neither the owner nor the producer of mineral wealth in the US, as is the case with government ownership of mineral wealth in many other export-oriented nations. Thus, the soft power afforded to the US government is facilitated by the unique regulatory and market institutions established in the US that allows the private sector's commercial development of oil and gas.

In general, legal institutions that place mineral rights in the hands of landowners and allow intellectual and physical property to be monetized have led to a regulatory framework in the US that is highly conducive to innovation and entrepreneurial activity across the energy sector. In the oil and gas space, incentives for domestic development derive from transparent, market-driven prices and a low cost to lift and move supplies. Hence, domestic production is very sensitive to the availability of capital and infrastructure. If anything disrupts the availability of either capital or infrastructure, production can grind to a halt in the affected region. This complicates the calculus around policy formation at the federal level, particularly when compared to the local level.[2]

As the US increases its exports of crude oil, petroleum products and natural gas, its influence expands into those nations that increasingly rely on imports to satisfy their energy appetites associated with economic growth. In general, expanded US production renders global supply to be more price responsive, and, as a result, carries an energy security benefit to consumers

[2] See "The Market Impact of New Natural Gas-Directed Policies in the United States" (Feb 2015) by Kenneth Medlock and Peter Hartley, available online at https://www.bakerinstitute.org/research/north-american-energy/.

everywhere. As argued in previous Baker Institute research, this also benefits US foreign policy endeavors in dealing with potential hostile oil-producing nations, and provides stability to the global oil market.[3] But, again, infrastructure is required to facilitate these goals.

Infrastructure, Competition and Energy Sector Evolution

The discussion heretofore has focused on a general framework for evaluating the role of infrastructure in trade and in facilitating US shale. But, to be clear, infrastructure plays an equally important role in the commercialization of new energy technologies and resources. One example that highlights the interdependent role of regulatory environment and infrastructure is found in electricity markets in Texas. Wholesale and retail competition were introduced in the State of Texas following the passage of Senate Bill 7. Since, competitive pressures in the retail power sector have forced firms to differentiate themselves by offering specific technologies and energy services. This has, in turn, unlocked the power of *revealed consumer preference* that matriculates through to investments in the wholesale generation and distribution of electricity. For instance, Texas now has more wind generation capacity than the entire rest of the US combined. Make no mistake, wind capacity investments have benefitted greatly from overt policy support, but they have also been propelled by consumer demands that have been made explicit through active marketing of renewable energy by retail providers. Moreover, as wind capacity investments have grown, massive transmission infrastructure investments have been made to connect resources to consumers. Similarly, some retail energy service providers have expanded their offerings into the introduction of smart technologies and distributed generation assets, which represent infrastructure investments at the commercial and residential levels. Thus, the regulatory and market environment along with the expansion of infrastructure have been critical for unlocking wind resource opportunities and pushing distributed generation and energy efficiency (albeit to a lesser extent) in Texas.[4]

Infrastructure also plays a vital role in the evolution of the transportation sector. The transportation sector has historically been dominated by crude oil products, a reality leveraged by a very large and redundant fuel delivery infrastructure. Redundancy, in particular, is a product of scale and is facilitated by multiple points of access to the primary fuel, including storage either onsite or near the refueling location. If other fuels are to successfully compete into the transportation sector, infrastructure is vital. And, the fuel must be reliable, which highlights the role of *redundancy* as an important aspect of fuel delivery infrastructure.

Natural gas is one fuel that has been discussed as having potential to penetrate the transportation sector. Currently, natural gas use for vehicle fuel is only about 0.15% of total natural gas use and

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[3] See "To Lift or Not to Lift? The US Crude Oil Export Ban: Implications for Price and Energy Security" (March 2015) by Kenneth Medlock, available online at https://www.bakerinstitute.org/research/north-american-energy/
[4] See "Electricity Reform and Retail Pricing in Texas" (June 2017) by Peter Hartley, Kenneth Medlock, and Olivera Jankovska, available online at https://www.bakerinstitute.org/research/north-american-energy/

represents about 2.8% of total transportation fuel use.[5] So, natural gas represents a relatively small fraction of the transportation sector. For this to change, scale comes into full focus, meaning substantial investment is required in natural gas fueling infrastructure along the nation's transportation network.[6] The ability to refuel becomes a very salient issue when one considers typical consumer driving behaviors. The flexibility and redundancy in the existing fuel delivery infrastructure (for gasoline) allows drivers the freedom to plan their activities without necessarily planning routes, which means "search costs" are significantly reduced when traveling.

Electrification of the vehicle fleet also poses some infrastructure challenges – with regard to power generation and transmission capacity and recharging outlets. In the near term, the existing generating fleet is sufficient to meet almost any expectation of electricity demand growth associated with electric vehicle (EV) adoption. In addition, recharging may be sufficient for low levels of EV penetration, but as more consumers drive EVs, scale effects begin to take hold and more recharging infrastructure will be required. Just as with natural gas into transportation, the location of re-charging stations also becomes relevant when long distance travel is desired. Even if the proverbial "chicken-and-egg" problem of vehicles and infrastructure can be overcome, the resulting requirements for new electric generation capacity – regardless of fuel type – if EVs adoption accelerates could be significant.[7] While renewable energy sources could arguably meet some of the incremental demand, the majority would likely be met by natural gas. Accordingly, this highlights another set of infrastructure requirements – added power generation and electricity distribution capacity as well as pipeline infrastructure enhancements.

Concluding remarks

Energy is critical to modern economic activity. This is, in fact, why energy security concerns – either discussed in the context of domestic reliability or international access – are such a critical component of energy policy discourse. Although not always explicit in these conversations, infrastructure is a prerequisite to the provision of energy services. It is vital throughout the value chain regardless of the form of energy being addressed. The US has a unique set of regulatory and market institutions that have promoted commercial development of infrastructure that has conveyed significant benefit in the energy security domain. While there are likely things that can be improved at the margin, in the context of the global energy system, the US has a very dense, redundant and relatively reliable energy architecture. Of course, aging infrastructure requires maintenance and modernization to capture the latest technological innovations, and doing so will go a long way to ensuring a 21st century competitive advantage for US interests.

[5] The figures are derived from annual data for 2016 and are available online from the *Monthly Energy Review* published by the US Energy Information Administration, www.eia.gov.
[6] These arguments apply to compressed natural gas (CNG) as well as liquefied natural gas (LNG) vehicles.
[7] See, for example, "Energy Market Consequences of Emerging Renewable Energy and Carbon Dioxide Abatement Policies in the United States," by Peter Hartley and Kenneth B Medlock III (Sept 2010), available at https://www.bakerinstitute.org/research/energy-market-consequences-of-emerging-renewable-energy-and-carbon-dioxide-abatement-policies-in-the/.

The CHAIRMAN. Thank you, Dr. Medlock.
Mr. Santa, welcome.

STATEMENT OF HON. DONALD F. SANTA, PRESIDENT AND CEO, INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Mr. SANTA. Good morning, Chairman Murkowski, Ranking Member Cantwell and members of the Committee.

My name is Donald Santa, and I'm the President and CEO of the Interstate Natural Gas Association of America, or INGAA. Our members transport the vast majority of the natural gas consumed in the United States through a network of approximately 200,000 miles of interstate transmission pipelines.

Thank you for the opportunity to share INGAA's perspective on the evolution of the nation's natural gas transmission pipeline infrastructure and the lessons learned from that experience. My perspective on this subject is informed not only by my current role, but also by my experience as a member of the Federal Energy Regulatory Commission.

My testimony today will summarize four recommendations.

First, recognize that enhancements to the existing natural gas pipeline network will continue to be needed. While the U.S. has a robust, well-developed, natural gas pipeline network, sources of natural gas supply and consumption patterns will continue to evolve. Consequently, the U.S. will need a flexible and responsive natural gas pipeline network that can adapt to meet the public interest. This evolving situation is illustrated by the recent emergence of the Permian Basin as a significant source of associated gas that is close to markets on the Gulf Coast and in Mexico. Additional pipeline capacity will be needed to bring this gas to market.

Second, value of the Natural Gas Act framework. The Natural Gas Act framework has been remarkably durable and should not be upset. The choice by Congress in 1938 to provide the Federal Power Commission and its successor, FERC, with latitude to interpret key statutory terms has enabled the Commission to adapt efficiently to the evolving market and public policy imperatives. Congress vested FERC with exclusive authority to authorize the construction of an interstate natural gas pipeline found to meet the public convenience and necessity. This exclusive authority is important for two reasons: first, FERC exercises its authority in the national interest; and second, while other federal agencies have mandates to issue impact-specific permits connected with proposed pipeline, only FERC has the project approval mandate.

Third, while FERC has overall responsibility for reviewing applications to construct new interstate natural gas pipelines, other federal agencies, and in some cases the states, review and permit discreet activities associated with pipeline construction. Experience demonstrates that the pace of action, or inaction, on these other permits can delay and frustrate the timely and predictable approval of pipeline projects. Congress' attempt to address the situation in the Energy Policy Act of 2005 by strengthening FERC's role as the lead permitting agency for interstate natural gas pipelines has not been entirely successful. We encourage the enactment of legislation now pending before Congress that would improve this process incrementally such as the House-passed H.R. 2910, Senator

King's Senate-introduced S. 1844, and parts of S. 1460, introduced by the Committee's Chairman and Ranking Member. These goals are also being advanced through Executive Branch reform initiatives such as Executive Order 13807 on establishing discipline and accountability in the environmental review and permitting process for infrastructure.

Fourth, cooperative federalism must be restored. As noted, federal law assigns to the states certain permitting responsibilities. For many years this worked smoothly as states reviewed applications for permits required by federal law and imposed reasonable conditions to protect their resources. Now, however, states are using this authority to dictate national energy policy. Specifically, the State of New York is attempting to use its authority under Section 401 of the Clean Water Act effectively to veto FERC's determination that a pipeline project is in the public convenience and necessity.

We respect the rights of states to protect the resources within their borders and support the cooperative federalism framework upon which many of these environmental statutes are based. This, however, is about more than just the respective roles of federal and state authority because one state's abuse of its role in this relationship can affect the ability of other states and their citizens to enjoy the benefits of interstate commerce. This is not cooperative federalism.

We do not believe that this result was intended by Congress. We encourage Congress to remedy the situation by providing guidance to the appropriate role of the state under Section 401 and by providing meaningful recourse should a state abuse its authority.

In conclusion, the United States has benefited greatly from a natural gas transmission pipeline network unlike any other in the world. These benefits include lower energy prices for consumers and industry, cleaner air through the displacement of less benign fuels and greater energy security. This would not have been possible without the pipelines that link the suppliers and consumers of natural gas.

Thank you.

[The prepared statement of Mr. Santa follows:]

Statement of

Donald F. Santa

President and CEO

Interstate Natural Gas Association of America

Before the

Committee on Energy and Natural Resources

United States Senate

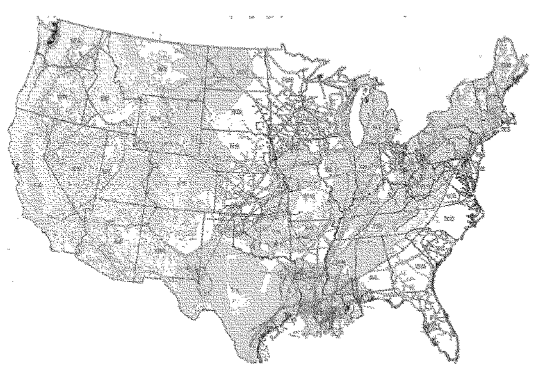
Regarding

The Evolution of Energy Infrastructure in the United States

and How Lessons Learned from the Past Can Inform Future Opportunities

February 8, 2018

Good morning Chairman Murkowski, ranking member Cantwell, and members of the committee. My name is Donald F. Santa and I am the president and CEO of the Interstate Natural Gas Association of America, or INGAA. INGAA represents the vast majority of the owners and operators of interstate natural gas transmission pipeline in the United States. The pipeline systems operated by INGAA's 27 member companies are analogous to the interstate highway system, transporting natural gas across state and regional boundaries. As you can see from the map below, this is an extensive energy infrastructure.



The committee has asked that we address the evolution of energy infrastructure in the United States and how lessons learned from the past can inform future opportunities. This testimony will focus on natural gas transmission pipelines. My perspective on this subject is informed not only by my current role as president and CEO of INGAA, but also by my experience as a member of the Federal Energy Regulatory Commission (1993-1997). During my tenure at FERC, the commission implemented the Order No. 636 gas restructuring rule that unbundled interstate natural gas pipeline services.[1]

The United States has a highly integrated pipeline network that can transport natural gas to and from nearly any point in the lower-48 states. This network of more than 210 natural gas pipeline systems includes approximately 300,000 miles of interstate and intrastate transmission pipelines, more than 1,400 compressor stations that maintain the pressure needed to transport natural gas supplies, and more than 400 underground natural gas facilities.[2] To put this into perspective, the mileage of domestic natural gas transmission pipelines is almost 6.5 times greater than the mileage of the U.S. interstate highway system. While my testimony will focus on natural gas transmission pipelines, it should be noted that there also are approximately 2.2 million miles of smaller diameter, lower pressure distribution pipelines used by local utilities to deliver natural gas to residential and commercial consumers.

Incremental additions of transmission pipeline capacity will continue to be needed as natural gas supply and consumption patterns continue to evolve. This conclusion was confirmed by a study performed in 2016 by ICF International for the INGAA Foundation.[3] While the study noted uncertainties about energy commodity prices, the global and domestic economic outlook, and the pace at which public policy will affect energy markets, even the low case scenario found a continued need for natural gas pipeline investment and expansion. Consequently, a legal framework and a public policy environment that supports the efficient, responsible and market-driven development of natural gas transmission pipeline infrastructure remains important.

This testimony will summarize: (1) the history of the U.S. natural gas transmission pipeline industry; (2) the legal framework for interstate natural gas pipeline regulation; (3) the role of private capital in the industry's development; (4) the evolution of policy for authorizing the construction of interstate natural gas pipelines; and (5) the safety and efficiency of natural gas transmission pipelines. I also will offer some lessons learned and recommendations.

A Brief History of the U.S. Natural Gas Transmission Pipeline Industry

The development of the nation's interstate natural gas transmission pipeline network is attributable to two factors. The first is the economic incentive to link major demand centers to distant supplies of

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[1] I also served as a member of the staff of the Committee on Energy and Natural Resources during enactment of the Natural Gas Wellhead Decontrol Act of 1989.

[2] The interconnectedness of this pipeline network can be demonstrated with several additional statistics. The pipeline network includes more than 11,000 delivery points, 5,000 receipt points and 1,400 points of interconnection where natural gas can be transferred between pipeline systems. There are 49 locations where natural gas can be imported or exported via pipeline, 8 liquefied natural gas (LNG) import facilities and one operational LNG export facility in the lower-48 states. Energy Info. Admin., *About U.S. Natural Gas Pipelines*; available at https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/index.html. Other LNG export facilities are under development, one of which will soon enter operation.

[3] ICF International, North American Midstream Infrastructure Through 2035: Leaning into the Headwinds (April 12, 2016), available at http://www.ingaa.org/File.aspx?id=27961&v=db4fb0ca.

natural gas. The second is the technology that made it possible for high-capacity pipelines to transport natural gas safely and economically over long distances.[4]

The Beginnings of the Interstate Pipeline Network

The true birth of the U.S. natural gas pipeline industry was in the 1920s when advances in pipe rolling, metallurgy and welding combined to make the long-distance transmission of natural gas practical. Subsequent advances in technology have enabled the industry to use increasing pipe diameters and pressures, which resulted in greater pipeline capacity and economies of scale.[5] For example, in 1930 the maximum diameter and design pressure for a natural gas pipeline was 20 inches and 500 pounds per square inch gauge (psig), while by 1980 the utilization of pipe up to 56 inches and 2,000 psig was contemplated (although as a practical matter, the maximum diameter pipe used in commercial applications is in the 42 inch range).

These advances spurred the first pipeline building boom. Between 1927-1931, about a dozen major natural gas transmission pipelines were constructed with each spanning more than 200 miles. Three of these systems stretched more than 1,000 miles. These systems connected gas supply from the Mid-Continent (Texas, Oklahoma and Kansas) to demand centers in the Midwest and Rocky Mountain region, supply from Louisiana to demand centers in the Midwest and South, and supply in California to in-state markets.

While pipeline construction subsided during the Great Depression, the fuel needs created by World War II provided the impetus for greater pipeline capacity. The 1,275-mile Tennessee Gas Transmission System from the Gulf Coast to the Appalachian region was authorized and constructed during the war. In addition, the federal government constructed two pipelines, the 1,340-mile Big Inch pipeline and the 1,475-mile Little Inch pipeline, terminating in Philadelphia and New York City, respectively, to ensure the security of crude oil and refined products from the Gulf Coast. Following the war, the "inch" pipelines were converted to transport natural gas and were sold to the private sector in 1947. The Big Inch pipeline route remains the foundation of the Texas Eastern Transmission system, while the Little Inch pipeline was converted to refined product transportation in 1957.

Post-War Pipeline Expansion

The United States' post-war economic expansion included a pipeline construction boom that lasted until the mid-1960s. Much of the backbone of today's natural gas transmission network was constructed at this time. At least 15 major interstate natural gas pipelines were added during this period and the interstate pipeline network matured to reach every major consuming market in the lower-48 states. In addition to major new trunklines, spurs were added to reach new markets and the capacity along existing pipeline corridors was expanded with parallel pipelines (looping) and added compression. In addition, the first significant pipeline connections with Canada and Mexico were established between 1957-1960.

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[4] The following summary of the evolution of the natural gas pipeline industry is based on Arlon Tussing and Bob Tippee, The Natural Gas Industry: Evolution, Structure and Economics 79-124, (2nd ed. 1995).
[5] Tussing and Tippee at 84.

Interstate Gas Shortages and Wellhead Decontrol

Pipeline construction waned during the late 1960s and for much of the 1970s. Federal wellhead price controls on natural gas dedicated to the interstate market, first imposed in the mid-1950s, created demand for natural gas among industrial consumers, because regulation constrained prices to artificially low levels. The Federal Power Commission (FERC's predecessor) discouraged new pipeline construction to preserve interstate gas for residential and commercial consumers. This situation worsened in the 1970s, as dwindling supplies of natural gas dedicated to the interstate market had to be rationed via end-use curtailment. The interstate natural gas shortages and overall pessimism about natural gas supply resulted in a significant contraction of the US natural gas market that finally bottomed out in the mid-1980s. It took until 1991 for the domestic natural gas market to grow back to the previous peak set in 1972.

Congress ultimately responded by enacting the Natural Gas Policy Act of 1978, a complicated statute that eliminated the distinction between the interstate and intrastate natural gas commodity (or "wellhead") markets, provided incentive pricing for multiple categories of new natural gas production, and began a phased wellhead decontrol that culminated in 1985 with the elimination of all remaining price caps on new (post-NGPA) natural gas production. The NGPA also encouraged linkage of the heretofore separate interstate and intrastate natural gas transmission pipeline systems by offering limited federal regulation for intrastate pipelines that established such interconnections.

Given the dim supply outlook, it was not surprising that few new natural gas transmission pipelines were constructed during this period. The significant exceptions were the "prebuild" legs of the Alaska Natural Gas Transportation system, a proposed and approved pipeline intended to transport natural gas from Alaska's North Slope to the lower-48 states. While ANGTS ultimately was not constructed, the eastern and western "prebuild" legs established important connections between natural gas supplies in Western Canada and consuming markets in the US Pacific Coast and Midwest regions.

Restructuring: A New Model

By the early 1980s, the US had entered a long period of natural gas oversupply.[6] This supply glut, known as the "gas bubble," lasted until the end of the next decade. Wellhead decontrol triggered a series of events that resulted in a profound restructuring of US natural gas markets, the natural gas pipeline industry, and the incentives for developing new natural gas pipelines. Beginning with Order No. 436 in 1985, a series of FERC orders transformed interstate natural gas pipelines from gas merchants into open access transporters that had completely exited the merchant function. As merchants, interstate pipelines were supply aggregators that purchased natural gas at the wellhead and resold it to downstream customers, typically local gas utilities, as a bundled product that included both the natural gas commodity and its transportation to the point of delivery. Now, as open access transporters, interstate pipelines sell natural gas transportation as an unbundled product on a non-unduly

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[6] The glut was the product of several factors. On the supply side, increased production resulted from the NGPA incentive prices and the rush by interstate pipelines to add gas to their supply portfolios after years of shortage. This occurred, however, as natural gas demand was dampened by the economic recession of the early 1980s and the Powerplant and Industrial Fuel Use Act, a federal law intended to discourage the consumption of oil and natural gas for electric generation and industrial processes.

discriminatory basis. FERC's restructuring orders sought to ensure truly non-discriminatory access to pipeline transportation and to facilitate competition in the supply and transportation of natural gas. As part of this, FERC encouraged pipelines to exit the merchant function entirely and imposed strict rules to preclude pipelines from favoring their merchant affiliates.[7]

Restructuring affected the incentives for developing new natural gas pipeline capacity. Before restructuring, interstate pipelines' incentive for developing new pipeline infrastructure was tied directly to their bundled merchant function, i.e., attaching new purchased gas supplies upstream and attaching new resale markets downstream. After restructuring, interstate pipelines are agnostic as to the ultimate ownership or use of the natural gas that is transported. New pipeline infrastructure is developed to satisfy the needs of the sellers and purchasers of the natural gas to be transported.

Natural gas wellhead decontrol and pipeline restructuring unleashed new competition among both gas suppliers and pipelines. This resulted in intense competition to serve new market opportunities in the late 1980s and early 1990s. Multiple pipeline companies competed to deliver gas from the US Southwest to markets in California. By 1992, two new interstate pipelines had been built into California and an existing pipeline expanded its capacity to deliver Canadian gas to the state. The other market that benefitted from the new competition was New England. The region historically had been served by long-distance pipelines originating in Texas and the Gulf Coast and depended on imported liquefied natural gas to meet peak winter demand.[8] With an opportunity for market growth by displacing heating oil in the residential and commercial market and fueling new gas-fired electric generators, local gas utilities wanted access to abundant gas supplies from Western Canada as a supplement to domestic supply. They formed a partnership with two pipeline companies to build a 370-mile pipeline originating at the Ontario-New York border in 1991-1992.

The end of the natural gas bubble coincided with the beginning of the new millennium. The market-clearing price for natural gas rose significantly, and there was pessimism about future gas supply from the lower-48 states and Western Canada. This sparked renewed interest in importing LNG and constructing the pipeline infrastructure needed to tap natural gas from Alaska's North Slope. One of the few domestic production bright spots was the Rocky Mountain region. New pipelines were built to connect this supply, including the 1,679-mile Rockies Express pipeline to transport natural gas from the Powder River Basin, to higher priced East Coast markets.

The Shale Boom: Replumbing the System

The natural gas supply picture shifted dramatically in the latter half of the 2010s with the new ability of producers to access the nation's abundant shale gas resource. This new abundance rendered obsolete plans to supplement lower-48 gas supply with imported LNG and North Slope natural gas. The first significant shale development occurred within the traditional oil and gas supply region of Texas and Louisiana (e.g., the Barnett and Haynesville Shales). Shale development quickly spread to other areas, including North Dakota (the Bakken Shale) and, most surprisingly, the East (the Marcellus and Utica

[7] Richard G. Smead, *How the Natural Gas Industry Became What It Is Today*, 33 Nat. Gas and Electricity 29,31 (2017).
[8] Even today, New England depends on LNG imports to supplement pipeline gas during the winter peak.

Shales). Furthermore, the shale boom brought not only abundant natural gas, but also crude oil and natural gas liquids.

The abundant and affordable domestic energy made possible by the shale boom has had a profound effect on the US and global energy economy. It also has created the need for new pipeline infrastructure to link producers and consumers. The location and abundance of shale resources has compelled fundamental changes in how the natural gas transmission pipeline network operates. Much of that network had been constructed to transport natural gas from the Gulf Coast and Texas to demand centers in the Northeast. This changed with the prolific Marcellus Shale on the doorstep of those markets. Furthermore, the Marcellus abundance was so great that it could not only meet demand in the East, but also could supply markets outside the region. As a result, pipeline flows have changed significantly. In addition to building the pipeline connections needed to supply consumers in the East, existing pipelines have been modified and new pipelines have been constructed to transport Marcellus gas to markets in other regions.

The shale abundance also triggered a demand response as natural gas became more affordable and as confidence grew that natural gas prices would remain stable. This included price-sensitive industrial consumers, natural gas-fired generators, residential and commercial markets still using fuel oil, and the opportunity to export US natural gas via pipeline to Mexico and in the form of LNG to global markets. The demand response to the shale abundance also created the need for pipeline infrastructure.

The shale revolution has compelled a significant "replumbing" of the US natural gas transmission pipeline network. This has involved both new "greenfield" pipeline infrastructure and repurposed existing infrastructure. For example, many of the pipelines that historically served the Northeast have been made bi-directional so that, depending on the season, natural gas can be delivered either to or from these markets. These modifications typically involve new compressors and some incremental pipeline facilities. The almost new Rockies Express is one of the pipelines that has been made bi-directional.

Legal Framework for Pipeline Regulation

The Natural Gas Act provides FERC with the exclusive authority to authorize the construction and operation of interstate natural gas pipelines that it finds to be in the "public convenience and necessity."[9] The NGA also provides that a pipeline found to be in the public convenience and necessity may exercise a federal right of eminent domain to acquire the land along its right of way.

The federal siting authority conferred by the NGA is unique among the statutes administered by FERC. For example, the Federal Power Act does not authorize FERC to site interstate electric transmission lines nor do the surviving portions of the Interstate Commerce Act authorize FERC to site oil pipelines. The uniqueness of natural gas transportation was acknowledged in the legislative history of the NGA, enacted in 1938. It recognized (1) that pipelines were the only practical means to transport natural gas long distances, (2) that the principal markets for natural gas were long distances and often multiple

[9] 15 U.S.C. § 717f.

states away from the sources of natural gas supply, and (3) that the states lacked the authority to deal with the need for interstate natural gas transportation.[10]

Interstate natural gas pipelines also are subject to the ratemaking sections of the NGA.[11] Under these provisions, the rates, terms and conditions for the interstate transportation of natural gas must be "just and reasonable" and "not unduly discriminatory".

The NGA does not define key terms, such as "public convenience and necessity," "just and reasonable," and "not unduly discriminatory." This has provided FERC the latitude to adapt its regulation to evolving imperatives provided it engages in reasoned decision making and remains within the bounds of its jurisdiction. For example, FERC's authority to act in response to "undue discrimination" was the basis for its sweeping natural gas restructuring orders, even though the statute nowhere mentions open access natural gas transportation. Similarly, the prerequisites for meeting the "public convenience and necessity" standard for obtaining authority to construct and operate an interstate natural gas pipeline have evolved to keep pace with market conditions and public policy priorities.

While FERC has exclusive authority under the NGA to find a proposed interstate natural gas pipeline to be in the public convenience and necessity, a pipeline operator also must comply with a host of other federal and, in some cases, state laws to obtain all permits required to proceed with construction.[12] FERC certificate orders are conditioned on obtaining all such authorizations.

Private Capital

The U.S. natural gas transmission pipeline industry has been funded entirely with private capital.[13] Unlike the electric power industry, there is no analog to the federal power marketing authorities or public power in the natural gas transmission pipeline industry.

In The Political Economy of Pipelines, Jeff Makholm describes the significance of this aspect of the US pipeline industry as follows:

> The most defining characteristic of US oil or gas pipelines is that they all have been financed by investor-owners under the assumption that each pipeline would pay for itself. Having a payment scheme in place from creditworthy parties for a new pipeline is a very big deal. It is the capital market's independent check on the wisdom of the line, its route, and size.[14]

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[10] Robert Christin, Paul Korman & Michael Pincus, *Considering The Public Convenience and Necessity in Pipeline Certificate Cases Under the Natural Gas Act*, 38 Energy L. J.,115, 117-120 (2017) (discussing the legislative history of the Natural Gas Act).

[11] 15 U.S.C. §§ 717c-717d.

[12] Examples of these permits and authorizations include consultation requirements under section 106 of the National Historic Preservation Act and section 7 of the Endangered Species Act, Coastal Zone Management Act consistency determinations, Bureau of Land Management right-of-way grants, and U.S. Fish and Wildlife Service special use permits. In addition, as discussed below, certain federal laws, such as the Clean Water Act and the Clean Air Act, assign permitting responsibilities to the states.

[13] Perhaps the only exception to this blanket statement would be the World War II "inch" pipelines that later were converted to transport natural gas. The federal presence in the pipeline industry was short lived, as these assets were sold to private, investor-owned pipeline companies over seven decades ago.

[14] Jeff D. Makholm, The Political Economy of Pipelines at 22 (2012).

FERC rate regulation under the NGA complements and reinforces the discipline imposed by private capital markets. Investors must accept that an interstate natural gas pipeline will be subject to cost-based rates and non-discriminatory open access conditions. In other words, even if there is great demand for natural gas transportation, a pipeline investor cannot extract economic rents greater than the FERC-approved rates nor can it limit access to the pipeline for its benefit.

Evolution of the FERC Certificate Process

As noted, Congress left FERC with significant discretion to interpret the phrase "public convenience and necessity." This has been recognized by the courts, which has allowed FERC considerable freedom in establishing the circumstances in which it will issue a certificate authorizing pipeline construction.[15]

The criteria for establishing that a proposed natural gas pipeline satisfied the "public convenience and necessity" were first articulated in the context of pipelines as aggregators of natural gas supply to fulfill their bundled merchant obligations. The inquiry focused on the sufficiency of the gas reserves that would support the proposed pipeline. In addition, FERC for many years consolidated competing applications for a single consolidated hearing. Under the *Ashbacker* doctrine, FERC held hearings to determine how much pipeline capacity would be needed in a defined area and then decided which of the competing projects would best be able to fulfill those needs.[16]

The Boundary Gas proceeding illustrates the insufficiency of this prior model. Boundary Gas, Inc. filed an application in 1980 for authority to import natural gas from Canada and resell that gas to distribution companies in the US Northeast. A year later, Tennessee Gas Pipeline Company filed an application to do the same. In addition, Tennessee filed an application to construct pipeline facilities with sufficient capacity to transport both its and Boundary's natural gas. Two other companies then filed applications to serve the same markets. In 1982, FERC consolidated the applications for evaluation in a single hearing. Certificates were finally issued by in 1987 – *seven years* after the need for additional gas was identified.[17]

FERC ultimately stopped setting competing applications for hearing, having concluded that "allowing market forces to determine the success or failure of the projects is the most efficient mechanism to assure the maximum use of facilities."[18] FERC realized that the public convenience and necessity criteria and the comparative hearing procedures designed for bundled merchant pipelines no longer fit the new market dynamic it had created. It recognized that "market forces could be relied on to determine the ultimate need for the facilities so long as the consumer was protected."[19]

This last point highlights an important shift in FERC's regulatory philosophy as it restructured the natural gas market to ensure that consumers benefitted from the wellhead decontrol enacted by Congress. Its regulation of natural gas transportation has evolved into a hybrid model with elements of both

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[15] *FPC v. Transcontinental Gas Pipeline Co.*, 365 US 1, 7 (1961).
[16] *Ashbacker Radio Corp. v. FCC*, 326 U.S. 327 (1945).
[17] *Boundary Gas, Inc.*, 40 FERC ¶ 61,088 (1987). Boundary is not an isolated example. It took more than five years (1985-1990) for FERC to sort through competing applications for new pipelines to serve California. During these proceedings, FERC policy evolved to the position that project sponsors' assumption of risk eliminated the need for comparative hearings.
[18] *Islander East Pipeline Co.*, 100 FERC ¶ 61,275, at P 51 (2002).
[19] *Regulation of Natural Gas Pipelines After Partial Wellhead* Decontrol, 33 FERC ¶ 61,007 (1985).

traditional regulation where appropriate and much lighter-handed regulation where competition is evident. Incumbent customers pay cost-based tariff rates and are shielded from the cost of new facilities from which they do not benefit. Meanwhile, the market drives the development of new and expanded pipeline infrastructure, as pipeline developers compete for shipper commitments and negotiate rates subject to the availability of a cost-based default rate.

The market for existing pipeline capacity also is robust, as parties can freely buy and sell point-to-point transportation capacity rights in a highly transparent secondary market. The pipeline capacity market both facilitates the competitive natural gas commodity market and sends important price signals about the value of pipeline capacity and the need for additional pipeline capacity.[20]

FERC's refocusing of the criteria for determining public convenience and necessity culminated in the 1999 FERC Policy Statement, Certification of New Interstate Natural Gas Pipeline Facilities.[21] The policy statement identifies the specific goals to be achieved by an effective policy and outlines a mechanism for achieving those goals in specific cases. FERC specifically stated that an effective policy "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."[22]

By requiring that new pipeline projects be independently viable, the policy statement both protects existing customers and establishes a powerful incentive against overbuilding. Incremental pricing (i.e., rates must recover the full cost of the new pipeline) ensures that new projects will not be subsidized by customers who do not benefit. Consequently, the project developer takes the economic risk and must weigh the impact of potential changes in market conditions over the life of pipeline.

The policy statement calls on project developers to eliminate or minimize the adverse effects on other pipelines and their customers and on the economic interests of landowners and communities along the proposed route. Pipeline applicants are expected to shape their proposals to achieve these goals before an application is filed, and FERC may impose additional conditions in the certificate to minimize adverse impacts.

The policy statement states that FERC will accept "any relevant evidence" of public benefits to demonstrate need for the project. Examples of such evidence include "meeting unserved demand, eliminating bottlenecks, access to new supplies, lower costs to consumers, new interconnects that improve the interstate grid, providing competitive alternatives, increasing electric reliability, or advancing clean air objectives." FERC added, however, that precedent agreements (customer contracts) still "constitute significant evidence of demand." In practice, pipeline applicants and FERC continue to rely heavily on precedent agreements as an objective demonstration of need; applicants nonetheless frequently include supplementary evidence along the lines suggested by the policy statement.

Finally, the policy statement provides that FERC will balance the "evidence of public benefits to be achieved against the residual adverse effects." To receive a certificate, an applicant must demonstrate that the public benefits of the project are proportional to any adverse impacts.

[20] Makholm at 118-119.
[21] *Certification of New Interstate Nat. Gas Pipeline* Facilities, 88 FERC ¶ 61,277 (1999).
[22] 88 FERC ¶ 61,277 at p. 61,743.

FERC Chairman Kevin McIntyre has announced that the commission this year will take a "fresh look" at the 1999 policy statement. Various parties have asserted that subsequent changes in energy markets and energy policy call into question whether the policy statement remains appropriate for reviewing applications for new natural gas pipelines. While there have no doubt been significant changes since 1999, I strongly suspect that the "fresh look" will conclude that the policy statement remains an efficient framework for FERC to determine whether a proposed pipeline is required by the public convenience and necessity. The issues raised by parties in current pipeline certificate proceedings are all capable of being addressed by the policy statement as it now exists.

Pipeline Efficiency

Transporting natural gas via pipeline is an effective and efficient means of delivering energy over long distances. Viewed in equivalent energy terms and equivalent transport distances, natural gas pipelines consume an average of two to three percent of throughput to overcome frictional losses compared to electric transmission lines, which lose six to seven percent of the energy they carry due to electric resistance.[23]

The "efficiency" of interstate natural gas pipelines can be viewed from two principal perspectives: economic efficiency and transportation efficiency. Economic efficiency measures the delivered cost to customers compared to the cost of the natural gas, accounting for both fuel cost and transportation rates. The overall system transportation efficiency is a measure of the fuel and/or electric energy used to transport natural gas and is a function of the overall system design (the hydraulic efficiency), how the system is operated, and the efficiency of individual components (such as the compressor units).[24]

Economic efficiency sometimes limits a pipeline company's ability to improve transportation efficiency. This occurs when the end-use market will not tolerate the price increase necessary to recover the cost of a measure that would improve transportation efficiency.

Pipeline companies strive to be as efficient as possible, yet must balance efficiency with the need to provide reliable and flexible service to customers. For example, pipeline companies often guarantee a sufficiently high delivery pressure so that local distribution company customers do not need to install additional compression behind their city gates. While this may reduce the transportation efficiency of the interstate pipeline, it increases the overall efficiency of the wellhead-to-burnertip value chain. Also, the increasing use of natural gas to generate electricity, both as part of the overall fleet of electric generators and as a back-up to intermittent sources of renewable power, means that pipelines do not operate as efficiently as they could if demand were constant and predictable. This reduced efficiency, however, is more than offset by the overall environmental and public health benefits gained by the increased use of natural gas to power generation. The interstate natural gas pipeline industry provides a flexible transportation service that accommodates wide variations in the demand for delivery of natural gas to a diverse market of end-use consumers, and thereby enhances the efficiency of the entire U.S. energy value chain.

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[23] Energy Information Administration, Frequently Asked Questions (national-level losses were 6.5 percent of total electricity disposition in 2007), available at http://tonto.eia.doe.gov/ask/electricity_faqs.asp#electric_rates2.

[24] The attached INGAA white paper, Interstate Natural Gas Pipeline Efficiency (October 2010), provides background on pipeline and compressor station design and technology and the factors that affect the efficiency of a pipeline system.

It is important to recognize the impact of natural gas wellhead decontrol and pipeline restructuring. Both were about competition and choice, and interstate pipelines are the conduit for physically delivering the benefits of competition and choice to customers. A network of competitive, open access pipelines makes the overall market more efficient, providing natural gas sellers with access to multiple markets and natural gas consumers, with supply options previously unattainable.

The competitive market for natural gas transportation services also influences decisions by natural gas pipeline companies about investing in pipeline system efficiency improvements. Before investing, pipeline companies want assurance that the capital expenditures will reduce the cost to operate the pipeline, increase business for the pipeline company, or are needed to provide safe and reliable service.

Pipeline Safety

Pipelines are the safest mode of energy transportation. The gas transmission pipeline industry's commitment to improving its safety performance continuously is evidenced by the record. Data from the Pipeline and Hazardous Materials Safety Administration indicates an approximately 90 percent decrease in pipeline leaks over the past three decades. Furthermore, advances in inline inspection technology since the early 2000s have revolutionized pipeline safety by enabling more accurate and expansive assessments of pipeline system integrity. Operators have leveraged these technologies to attack challenging pipeline integrity threats. Over the last decade, manufacturing-related incidents have decreased approximately 80 percent and external corrosion-related incidents have decreased approximately 50 percent. Pursuant to a National Transportation Safety Board recommendation, operators and regulators are working now to implement structured, risk-based pipeline safety management systems. Safety management systems are being used to strengthen safety culture, identify innovative strategies for reducing incidents and sustain the continuous improvement.

Lessons Learned

Enhancements to the natural gas pipeline network will continue to be needed

There is no doubt that the U.S. has a robust, well-developed natural gas pipeline network. Nonetheless, sources of natural gas supply and consumption patterns will continue to evolve. Consequently, a flexible and responsive natural gas pipeline network that can adapt to meet the public interest still will be needed.

This evolving situation is illustrated by the recent emergence of the Permian Basin as a significant source of associated gas[25] that is close to markets on the Gulf Coast and in Mexico. Additional pipeline capacity will be needed to bring this gas to market or the nearest liquid trading point. The 2016 report by ICF International referenced earlier found that between 44 and 59 billion cubic feet per day of natural gas transportation capacity would need to be added in the US and Canada by 2035.[26]

[25] Associated gas is natural gas produced in conjunction with petroleum, either dissolved in the oil or as a "gas cap" above the oil in the reservoir.
[26] ICF International, North American Midstream Infrastructure Through 2035: Leaning into the Headwinds (April 12, 2016) at 7.

As noted in this testimony, both the capital markets and FERC's policy statement ensure that pipelines will not be constructed unless there is a demonstrated need. FERC's policies will continue to protect consumers and the resources and interests potentially affected by the pipeline.

Value the Natural Gas Act framework

The Natural Gas Act framework has been remarkably durable and should not be upset. The choice by Congress in 1938, and in early amendments to the NGA, to provide FERC with latitude to interpret statutory terms such as "just and reasonable," "unduly discriminatory" and "public convenience and necessity" has enabled the commission to adapt efficiently to an evolving market and contemporary public policy.

Congress vested FERC with exclusive authority to authorize the construction and operation of an interstate natural gas pipeline found to meet the public convenience and necessity. This exclusive authority is important in two respects. First, FERC exercises its authority in the national interest. While FERC may consider the effect of a proposed pipeline on the parochial interests of an individual state, its decisions ultimately are made to promote the national interest.[27] Second, while multiple federal agencies have mandates to issue impact-specific permits in connection with a proposed pipeline, FERC is the only agency that has been vested with a project-approval mandate.

The temptation to dictate FERC's agenda via prescriptive tweaks to the NGA should be resisted. Statutes drafted with the level of detail seen in some other statutory schemes that are not administered by an independent agency like FERC are destined to be overtaken by events and ultimately will hamstring the regulatory as it attempts to adapt policy and regulation to new conditions. This can be true even with statutory changes intended to "help" the regulator.[28]

Coordinate the Permitting Process

While FERC has overall responsibility for reviewing applications to construct new interstate natural gas pipelines, other federal agencies have impact-specific mandates that are fulfilled by reviewing and permitting discrete activities associated with pipeline construction. In addition, in certain cases, the states have been assigned authority for fulfilling responsibilities under federal law. Experience demonstrates that the implementation of these other mandates can delay and frustrate the timely and predictable approval of pipeline projects.

These multiple statutory mandates need to be reconciled, with further direction from Congress, to give proper effect to each. This is not about preempting or limiting the ability of any agency to perform the

[27] For example, during the early development of the natural gas pipeline network, FERC's predecessor routinely acted to authorize proposed interstate pipelines notwithstanding the objections of states that sought to husband natural gas for their own benefit. See Tussing and Tippee at 96 (Texas and Louisiana objections to the proposed Tennessee Gas Transmission Co. pipeline). *See also* Tussing and Tippee at 102 (eastern consuming states objection to proposals to expand the Tennessee Gas Transmission Co. and Texas Eastern Corp. systems into New England).

[28] For example, in the Energy Policy Act of 2005, Congress enacted a new NGA section 4(f) intended to assist FERC in encouraging the development of underground natural gas storage in markets lacking such facilities. Because section 4(f) imposed so many conditions on FERC's ability to authorize such facilities, next to no applicants have taken advantage of this provision. In hindsight, Congress would have been better to leave FERC to work through the problem using the latitude provided by the existing statute.

role given to it by the Congress. Rather, it is about establishing governing principles to ensure that no federal agency prevents another from fulfilling its statutory mandate.

Congress attempted to address this situation by enacting the new NGA section 15 (a)-(d) on process coordination and section 19(d) on judicial review as part of the Energy Policy Act of 2005. This legislation was intended to strengthen FERC's role as the lead permitting agency for interstate natural gas pipelines. Unfortunately, these provisions have not been entirely successful in accomplishing their intended purpose. Legislation now pending before Congress, the House-passed H.R. 2910 and the Senate-introduced S. 1844, proposes incremental improvements to advance the goals of the EPAct 2005 amendments. We encourage enactment of these provisions as part of an infrastructure bill or via another suitable legislative vehicle.

These goals also are being advanced through executive branch reform initiatives. For example, implementation of Executive Order 13807, Establishing Discipline and Accountability in the Environmental Review and Permitting Process for Infrastructure, has the potential to achieve the harmonization in the permitting process that we believe is needed.

Restoring Cooperative Federalism

As noted, federal law assigns certain permitting responsibilities to the states. For many years, this worked smoothly as states reviewed applications for permits required by federal law and imposed reasonable conditions to protect their resources. Now, however, states are using this authority to dictate national energy policy. Specifically, the State of New York is doing so in connection with its authority to grant a certification pursuant to section 401 of the Clean Water Act that a discharge into navigable waters will comply with applicable water quality standards. New York is attempting to use this authority effectively to veto the determination by FERC that a project is in the public convenience and necessity.

We respect the rights of states in protecting the resources within their borders and support the "cooperative federalism" framework upon which many of these environmental statutes are built. This, however, is more than just a discussion about the respective roles of federal and state authority, because one state's abuse of its role in this relationship can affect the ability of other states and their citizens to enjoy the benefits of interstate commerce. For example, the State of New York's actions to thwart the construction of an interstate pipeline that FERC has found to be in the public convenience and necessity frustrates the ability of neighboring states to enjoy the benefits associated with that pipeline. The Commonwealth of Pennsylvania and its citizens are denied the benefits of a downstream market for their natural gas production and the downstream New England states and their consumers are denied the benefits of the lower energy costs made possible by additional natural gas supplies. That is not cooperative federalism.

We do not believe that this result is what was intended by Congress when it enacted this statute. While we believe that steps can be taken administratively to circumscribe a state's ability to overstep the bounds of its authority under section 401, support and relief from Congress is needed to achieve clarity. We encourage Congress to provide oversight to ensure that section 401 is implemented as intended and to remedy the situation by providing guidance as to the appropriate role of a state under section 401 and by providing meaningful recourse should a state abuse its authority.

Conclusion

The United States has a natural gas transmission pipeline network unlike any other in the world.[29] The combination of the robust physical infrastructure and the "open architecture" model for gas transportation provide the foundation for the most competitive natural gas market in the world.[30] The ability to expand and modify this network quickly and efficiently in response to evolving market imperatives has enabled the United States to benefit rapidly from the shale abundance. These benefits include lower energy prices for consumers and industry, cleaner air through the displacement of less benign fuels, and greater energy security. This would be impossible without the pipelines that link the suppliers and consumers of natural gas.

[29] Central Intelligence Agency, *World Factbook Field Listing: Pipelines*; available at https://www.cia.gov/library/publications/the-world-factbook/fields/2117.html.

[30] The U.S. is the only competitive natural gas commodity market in the world to exhibit competitive spot and futures trading. Makholm at 118.

Interstate Natural Gas Pipeline Efficiency

Interstate Natural Gas Association of America
Washington, D.C.

October 2010

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EXECUTIVE SUMMARY

The North American natural gas transportation system is a complex network of interstate and intrastate pipelines designed to transport natural gas from producing regions to end-use markets. As of 2008, the United States and Canadian pipeline network consisted of approximately 38,000 miles of gathering pipeline and over 300,000 miles of transportation pipeline, of which interstate pipelines composed 217,000 miles.[1] In 2007, United States interstate pipelines transported 36 Trillion cubic feet (Tcf) of natural gas on behalf of customers.[2] Total United States storage capacity is 8.6 Tcf.[3]

Transporting natural gas via pipeline is an effective and efficient means of delivering energy over long distances, connecting production sources to local utilities, industrial plants and natural gas–fired electric power plants. Viewed in equivalent energy terms and equivalent transport distances, natural gas pipelines consume an average of two to three percent of throughput to overcome frictional losses compared to electric transmission lines, which lose six to seven percent of the energy they carry due to electric resistance.[4]

This report documents efficiency advances in the natural gas transportation pipeline industry since the advent of long mileage pipelines in the 1920s. This report also describes the factors that contribute to overall pipeline system efficiency and pipeline company decision-making with respect to efficiency improvements. In addition, this report reviews regulatory and environmental policies as well as competitive market pressures that affect a pipeline company's ability to maximize the efficient use of its system.

The "efficiency" of interstate natural gas pipelines can be viewed from two main perspectives: economic efficiency and transportation efficiency. Economic efficiency measures the delivered cost to customers compared to the cost of the natural gas, taking into account both

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[1] Energy Information Administration, *About U.S. Natural Gas Pipelines*, available at http://www.eia.doe.gov.
[2] *Id.*
[3] Energy Information Administration, *Monthly Underground Natural Gas Storage Capacity*, available at http:///www.eia.doe.gov.
[4] Energy Information Administration, *Frequently Asked Questions* (national-level losses were 6.5 percent of total electricity disposition in 2007), available at http://tonto.eia.doe.gov/ask/electricity_faqs.asp#electric_rates2.

fuel cost and transportation rates. The overall system transportation efficiency is a measure of the fuel and/or electric energy used to transport natural gas and is a function of the overall system design (the hydraulic efficiency), how the system is operated, and the efficiency of individual components (such as the compressor units).

Economic efficiency sometimes limits a pipeline company's ability to improve transportation efficiency. This occurs when the end-use market will not tolerate the price increase necessary to recover the cost of a measure that would improve transportation efficiency.

Pipeline companies strive to be as efficient as possible, yet must balance efficiency with the need to provide reliable and flexible service to customers. For example, pipeline companies often guarantee a sufficiently high delivery pressure so that local distribution company customers do not need to install additional compression behind their city gates. While this may reduce the transportation efficiency of the interstate pipeline, it increases the overall efficiency of the wellhead-to-burnertip value chain. Also, the increasing use of natural gas to generate electricity, both as a back-up to intermittent sources of renewable power and as a cleaner alternative to coal-generated power, means that pipelines do not operate as efficiently as they could if demand were constant and predictable. This reduced efficiency, however, is more than offset by the overall environmental and public health benefits gained by the increased use of natural gas to power generation. The interstate natural gas pipeline industry provides a flexible transportation service that accommodates wide variations in the demand for delivery of natural gas to a diverse market of end-use consumers, and thereby enhances the efficiency of the entire United States energy value chain.

It is important to recognize the impact of natural gas wellhead decontrol and pipeline restructuring. Both were about competition and choice, and interstate pipelines are the conduit for physically delivering the benefits of competition and choice to customers. A network of competitive, open access pipelines makes the overall market more efficient, providing natural gas sellers with access to multiple markets and natural gas consumers, with supply options previously unattainable.

The competitive market for natural gas transportation services also affects decisions by natural gas pipeline companies about investing in pipeline system efficiency improvements. Before investing, pipeline companies want assurance that the capital expenditures will reduce the cost to operate the pipeline, increase business for the pipeline company, or are needed to provide safe and reliable service.

Key conclusions of the report are as follows:

1. Each pipeline system is the unique result of its age, geographic location, original design, subsequent modifications, and shifting supply/demand patterns. As a result, technologies that may improve efficiency or may be cost effective on one pipeline system may not be feasible or economic on another pipeline system. A "one-size-fits-all" approach to transportation efficiency targets or technology prescriptions, such as mandatory efficiency targets or forced adoption of specific technologies, therefore is not practical.

2. Throughout its history, the interstate pipeline industry has invested in advances in pipeline, compressor and prime mover technologies that have contributed to continuous gains in the overall transportation efficiency of the natural gas pipeline network. Because pipeline companies have exploited the major economic technological efficiency improvements in the industry to date, there are limited opportunities for significant near-term efficiency gains.

3. The greatest opportunity for maximizing either economic or transportation efficiency is in the initial design and construction phase of a major facility. Maximum design efficiency is achieved by selecting the optimum balance of pipeline diameter, operating pressure and compression facility components for a specified flow rate. Once the pipeline has been built based on initial demand assumptions, it generally is not cost effective to change original design elements (such as maximum operating pressure) significantly to meet changed demand. While new energy saving technologies can be retrofitted on operating pipelines, the efficiency savings must generate sufficient revenue to balance the upfront capital costs, and operation and maintenance costs over the life of the retrofit projects.

4. Design efficiency and operating efficiency are not the same and should not be confused. Pipelines typically are designed for optimal transportation efficiency at peak flows, but frequently operate at lower flow rates, which may result in lower fuel consumed per unit of throughput. For that reason, fuel savings predictions for certain

technologies based on peak flow design conditions may not be realizable or economic under actual operating conditions.

5. The pipeline industry considers several key issues in evaluating whether to invest in an efficiency improvement. These include:

   - Whether newer equipment can be integrated with the existing equipment and the extent of the anticipated efficiency improvement;
   - Whether the improvement will impact reliability and the ability to meet contract demand;
   - The upfront capital cost and projected operation and maintenance costs of running the equipment;
   - Fuel savings or other cost savings;
   - The facility run time and percent load of the compressor unit, since how often and how hard the compressor runs affects the potential efficiency gain and potential fuel savings of the investment; and
   - The willingness of customers and the marketplace to pay rates that fund the investment.

6. While natural gas pipeline companies and supporting industries continue to invest in research and development on efficiency technology, the competitive commercial environment created by the restructuring of wholesale natural gas markets has affected the economic incentives for incorporating innovations to improve the transportation efficiency of the natural gas pipeline system:

   - Because of service options now available, customers often are committing to firm transportation contracts with much shorter terms than in the past. As a result, pipeline companies face substantial risk for recovery of capital investments in long-term efficiency improvements;
   - Pipeline-on-pipeline competition has given many pipeline customers substantial bargaining power. In conjunction with the Federal Energy Regulatory Commission's (FERC's) incremental pricing policy (under which new customers

must pay the cost of facilities built primarily to serve them), customers have an incentive to pay only for efficiency expenditures that will benefit them directly; and

- Pipeline companies have an incentive to make efficiency investments to the extent they can recover their investment by retaining cost savings over a reasonable time period. Yet, when the cost of innovations exceeds what customers are willing to pay under their transportation contract with their pipeline company, there is little incentive for pipelines to assume the risk association with such investments.

7. Increasingly stringent environmental regulations also affect pipeline companies' ability to maximize both economic and transportation efficiency by influencing equipment choices and siting. If the pipeline is in an area with strict emissions limits, it may be foreclosed from employing what would otherwise be the most efficient equipment choices. For example, the pipeline company may have to install electric-powered compression instead of gas-powered compression (even if gas would be more efficient), or relocate compression to a less than optimal area outside of the non-attainment area, or even install larger diameter pipeline in lieu of additional compression (which may require additional right-of-ways and will be much costlier than compression). These choices actually may push the pipeline company to purchasing decisions that reduce either economic and/or transportation efficiency.

8. Uncertainty over the timing and content of pending and proposed climate change legislation and regulation deters investment in efficiency improvements aimed at reducing greenhouse gas (GHG) emissions. The concern is that investment today to achieve improvements in efficiency could be rendered obsolete if final climate change legislation or regulation compels a pipeline company to modify or improve its system in a different way. Further, should the Environmental Protection Agency (EPA) be prescriptive in what it considers Best Available Control Technology (BACT) for regulating GHGs under the Clean Air Act, BACT compliance may limit pipelines' options to improve efficiency when they install a new compressor or modify an existing one.

9. The pipeline industry enhances the efficiency of the overall energy grid by providing flexible and reliable service in response to customer demand and market conditions. That responsiveness may come at a cost. For example, interstate natural gas pipelines serve gas-fired power generators, which are probably the most reliable and cost-effective back-up source of power for intermittent energy sources such as wind and solar. But to serve that load, interstate pipelines must stand ready to ramp up quickly, operating their compressor units in off-design conditions that lower the transportation efficiency of their systems. Nevertheless, from a broader perspective, this pipeline operational flexibility inures to the benefit of the power industry and the Nation's energy needs.

A. HOW PIPELINES WORK

Natural gas is an odorless transparent gas, primarily composed of methane. The most economical and efficient way to transport natural gas is via pipeline under pressure.[5] Gas compressors are used to pack the gas molecules, reducing their volume and increasing the energy density of the fluid. Compressor stations, typically sited every 50 to 100 miles, keep the natural gas flowing by boosting the pressure of the gas to compensate for pressure losses along the pipeline. As with all flowing fluids (liquid or gas), friction causes pressure to drop as the compressed gas moves through the pipeline. The pressure losses and corresponding decrease in transportation efficiency are related to many factors such as pipeline diameter, operating pressure, throughput, and internal roughness of the pipeline. Other transportation efficiency losses occur at compressor stations in the compression process. Additional background on how to measure efficiency is provided in Appendix A.

The industry employs two types of compressors – reciprocating and centrifugal. Reciprocating compressors are positive displacement devices, i.e., devices that add pressure by compressing the gas through mechanical displacement, typically with a cylinder-piston combination (like a bicycle pump). Centrifugal compressors use impellers to translate rotational velocities into higher potential energy in the form of pressure, which compresses the natural gas molecules (similar to a fan or hair dryer).

Compressors are driven by prime movers (reciprocating engines, gas turbines or electric motors). Reciprocating compressors are driven typically by natural gas-powered reciprocating engines (similar to automobile engines with a piston and crankshaft) or electric motors. Centrifugal compressors are driven by gas turbines or electric motors. Because the demand for natural gas is not constant on an annual basis, most pipeline compressors do not run year round or consistently at full capacity. Properly maintained compressors and pipelines can function well for many decades and there are many examples of 30 to 50 year-old equipment still operating today.

[5] Vehicular/rail transport of compressed natural gas is not economically feasible because it is significantly less dense than a liquid (e.g., oil) or a solid (e.g., coal).

Storage facilities along the pipeline are another key component of a natural gas pipeline system. Pipelines use the same compression process and driver/compressor technologies to move gas in and out of pressurized geologic storage reservoirs. These facilities promote efficiency by enabling a pipeline company and its customers to maintain an inventory of natural gas along the pipeline for later withdrawal to meet peak demand.

B. PIPELINE SYSTEM EFFICIENCY

The "efficiency" of interstate natural gas pipelines can be viewed from two main perspectives: economic efficiency and transportation efficiency.

- Economic efficiency relies on providing the lowest delivered cost to customers, taking into account both fuel and transportation rates. Economic efficiency usually is measured in terms of cost per unit of throughput (i.e., dollars per thousand cubic feet or $/Mcf).
- Transportation efficiency is a function of the overall system design, the efficiency of individual components, and how the system is operated. Transportation efficiency is measured in terms of fuel or electric power burned per unit of throughput (i.e., British thermal unit (Btu) or KW/Mcf). Within this general definition of transportation efficiency, there are three other pertinent measures.
    - Hydraulic efficiency: As applied to pipelines, hydraulic efficiency is a measure of the loss of energy (pressure drop) caused by the friction of the flowing gas in the pipeline facilities.
    - Thermal efficiency: As applied to a prime mover (engine, turbine or motor) that drives a compressor, thermal efficiency measures how much of the potential energy of an input fuel or electric power is converted into useful energy that can be used to drive a compressor. The majority of energy that is not converted into useful energy is considered "waste heat" in the exhaust (such as noise), cooling and lubrication systems. The waste heat may be captured when economically feasible.[6]

[6] *See generally*, *Waste Heat Recovery Opportunities for Interstate Natural Gas Pipelines*, Prepared for INGAA by Bruce Hedman of ICF. February, 2008, and *Status of Waste Heat to Power Projects on Natural Gas Pipelines*, Prepared for INGAA by Bruce Hedman of ICF. November, 2009. For the

- Compressor efficiency: As applied to gas compressors, compressor efficiency measures how much energy is expended in compressing the gas compared to how much overall energy is used by the compressor. Inefficient compressors heat the gas instead of raising its pressure and thus have lower efficiency values.

The compressor unit efficiency (a product of the thermal and compressor efficiencies) and the pipeline hydraulic efficiency between compressor stations are variables that affect the overall system transportation efficiency. When designing its system, a pipeline company tries to optimize hydraulic efficiency through pipeline routing, pipeline diameter and operating pressure selections, and tries to optimize thermal efficiency and compressor efficiency through its compressor unit selections (including the engines, turbines, or electric motors that power the compressors).

Figure 1 below illustrates the linkage between economic efficiency and transportation efficiency.

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purpose of this report, INGAA will not address waste heat recovery. Please see the above referenced white papers for a full discussion of waste heat to power on interstate pipelines.

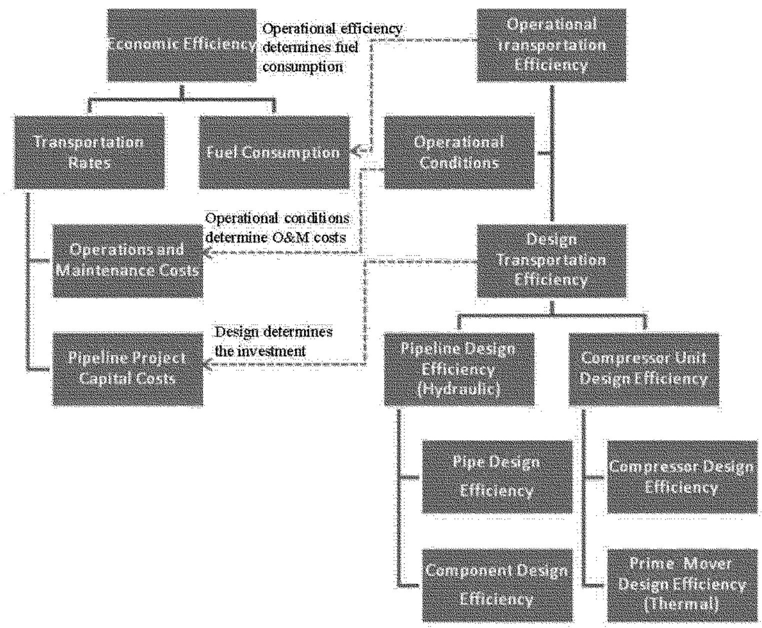

Figure 1. Linkage Between Economic and Transportation Efficiency

Design transportation efficiency (anticipated performance at a specific operating condition) is a combination of two separate components, the hydraulic efficiency of the pipeline and the efficiency of the compressor units at design conditions. The design hydraulic efficiency of the pipeline is based on the flowing frictional losses of the pipeline (diameter, pressure, roughness) and components (such as valves, regulators, and measurement devices) that the gas flows through. The compressor unit's design efficiency is a product of the design efficiency of the compressor (reciprocating or centrifugal) and the prime mover (reciprocating engine, gas turbine, or electric motor). A pipeline does not operate at design conditions for most of the year. The pipeline company operates its pipeline to meet its customers' contractual commitments. Variations in throughput due to changes in market demand and shifting supply sources, which affect how the system is utilized, and limitations on operating pressure determine the operational transportation efficiency of the pipeline system over time (how efficiently the pipeline operates compared to design conditions).

The economic efficiency of a particular pipeline is also a result of the pipeline system design and how the pipeline system is operated. The choice of pipeline diameter, components and compressor units determine the original invested cost of the pipeline. Those capital costs are combined with the predicted operation and maintenance costs of those particular design choices to establish gas transportation rates. In addition to transportation rates, the predicted use of pipeline compression (and the amount of fuel used and charged to customers) determines the design economic efficiency of a new project. Yet, since the pipeline often does not operate at design conditions, fuel usage may vary from predicted levels. Thus, operational economic efficiency often differs from design economic efficiency.

Basic economics may limit a pipeline company's ability to maximize the pipeline's overall transportation efficiency, such as when an efficiency improvement, particularly one with limited efficiency gains, cannot be cost justified or the cost recovery period is too long or too uncertain. Other competing parameters that influence pipeline decision-making on efficiency improvement projects may include future expansions, environmental restrictions, limitations on maximum allowable operating pressure (MAOP), siting concerns that may require rerouting the pipeline, and regulatory policies that encourage competition and expose the pipeline company to cost recovery risk. Federal regulatory policies have created a market for natural gas transportation that gives customers more bargaining power for lower cost service and shorter transportation contracts. At the same time, competition among pipelines serving the same market has created a natural incentive for pipeline companies to reduce costs and invest in higher efficiency technologies that can provide a competitive advantage.

HISTORY AND DEVELOPMENTS RELATED TO PIPELINE EFFICIENCY

A. MAJOR PIPELINE EFFICIENCY DEVELOPMENTS OVER THE YEARS

The modern day natural gas transportation system is a complex network of interstate and intrastate pipelines designed to transport natural gas from producing regions to end-use markets (see Figure 2). This network is the culmination of decades of design and construction, and includes 30 to 50 year old legacy engines,[7] older compressors with modern retrofit improvements, and new, state-of-the-art gas compressor systems. As of 2008, the United States and Canadian network consisted of approximately 38,000 miles of gathering pipeline and over 300,000 miles of transportation pipeline, 217,000 miles of which are operated by interstate pipelines.[8] Total capacity of the interstate natural gas pipeline grid in 2008 was approximately 183 Billion cubic feet per day (Bcf/d), which served to meet a major portion of the total United States and Canadian energy demand.[9] In 2007, United States interstate pipelines transported 36 Tcf of natural gas on behalf of customers.[10] In addition, total United States storage capacity is 8.6 Tcf.[11]

[7] Legacy engines used in the natural gas industry were relatively large, robust, slow speed (300 rpm) machines designed to operate continuously for years without a shutdown. Their use declined over time as the price of steel and construction costs escalated.
[8] Energy Information Administration, *supra* note 1.
[9] *Id.*
[10] *Id.*
[11] Energy Information Administration, *supra* note 3. The aggregate peak capacity for U.S. underground natural gas storage is estimated to be 3,889 Bcf.
http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/ngpeakstorage/ngpeakstorage.pdf

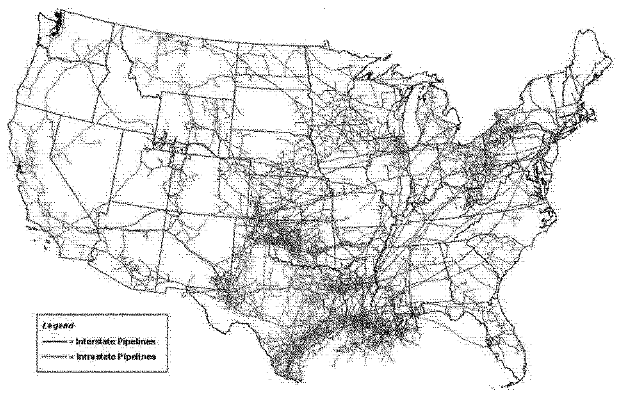

Figure 2. U.S. Natural Gas Pipeline Network

Natural gas pipeline technology has improved since 1929, when Peoples Gas Light & Coke Company completed the first long-haul pipeline, the Natural Gas Pipeline of America (NGPL). After World War II, the North American natural gas transportation system expanded substantially due to advances in metallurgy, steel pipe, welding techniques and compressor technology.

Since the 1950s, the general consensus on pipeline design was to design and build a pipeline using the combination of pipeline diameter and compression that would transport gas for the lowest delivered cost. Pipeline diameter is the biggest single variable in pipeline hydraulic efficiency. Advances in pipeline technology since the first long-haul pipeline have enabled pipelines companies to increase pipeline diameter and thus improve hydraulic efficiency. By increasing pipeline diameter and operating pressure, pipelines have been able to install less compression for the same throughput. Nonetheless, in determining the balance of pipeline and compression, the cost of the line pipe (the steel) was and remains a significant, if not the most significant, cost in pipeline construction.

In the 1950s, the dominant pipeline and compressor technology was the combination of largest available pipeline diameter (30-inch) with slow-speed integral reciprocating compressor units, i.e., units with the compressor integrated into the engine design. Rather than using a separate engine coupled through a crankshaft to a separate compressor, these "legacy" integral units directly incorporated reciprocating engines with reciprocating gas compressor cylinders. This allowed for smaller, more compact compressor units that could be installed at a lower cost. See Figure 3 below.

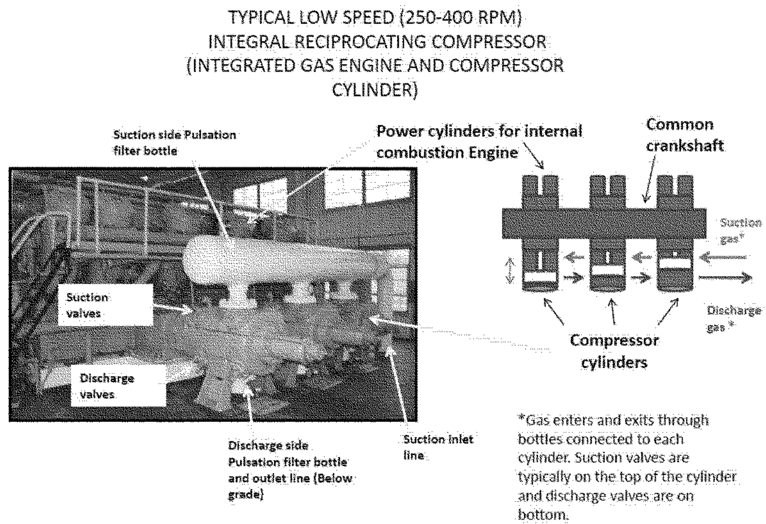

Figure 3. Integral Reciprocating Compressor

Beginning in the 1960s, improved metallurgy and manufacturing practices permitted the construction of larger diameter pipeline with higher strength steel to transport natural gas longer distances at higher operating pressures with less compression and at lower costs. Pipeline companies began experimenting with new, higher cost, internal coating technology that reduced friction, allowing pipelines to move gas even longer distances with even less compression, thus improving hydraulic efficiency between compressor stations. Since most areas were served by only one pipeline during the 1960s, and since the pipeline company provided a bundled sales and transportation service to customers, the pipeline company controlled when, how, and where gas would enter and move on its system. The pipeline company also would pack the line to maximize the system's operational flexibility by compressing gas above the intended delivery pressure in anticipation of customer demand. This practice still is utilized today to optimize compression efficiency to meet anticipated high demand periods. Pipeline companies often met fast-growing residential and commercial demand through additional mainline compressor stations that could offer the operating flexibility necessary to respond to new customers.

During the 1960s and 1970s, pipeline companies began to install centrifugal compressors driven by gas turbines. See Figure 4 below. Compared to integral reciprocating compressor units predominant in the 1950s, these centrifugal compressor units could be installed and maintained at a lower cost. Moreover, a pipeline company could purchase large centrifugal compressor units instead of multiple reciprocating compressor units at significant cost savings. During this period, integral reciprocating compressor technology stagnated and many suppliers ceased manufacturing large integral reciprocating compressors.

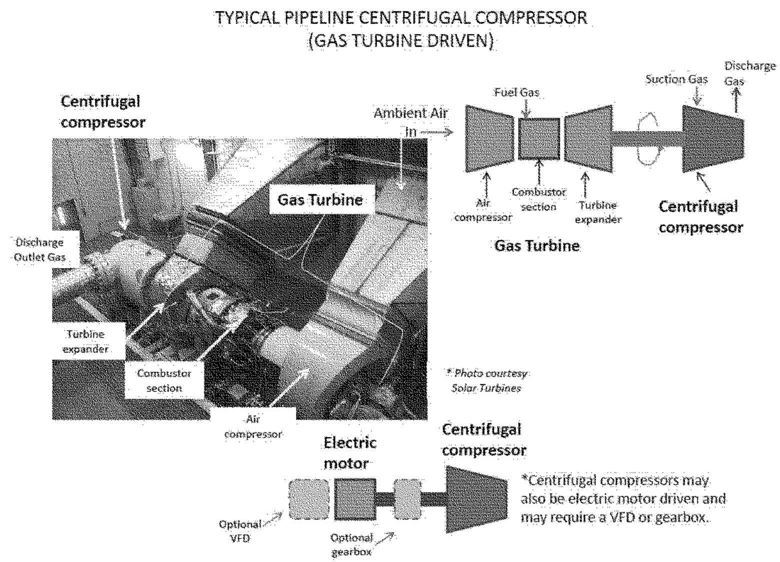

Figure 4. Gas Turbine Driven Centrifugal Compressor

In the 1970s, utilization of underground storage reservoirs located near market and supply areas permitted seasonal storage of gas, enhancing pipeline companies' ability to match supply and demand. Also, the pipeline industry adopted computer technology that permitted remote operation of facilities from a central gas control center. These and other computer-based technology advances improved the pipeline companies' ability to diagnose maintenance issues, and facilitated the later implementation of air emissions control technology and electronic timing controls.

Beginning in the 1980s, pipeline companies expanded the use of advanced pigging technology to clean and streamline the pipeline wall to reduce friction. In addition, modular construction of some newer gas turbine compressor units allowed pipeline companies to replace and overhaul separate modules. This reduced the downtime of high usage equipment and minimized the loss of operating transportation efficiency. Also, low emissions technology became commercially available, permitting the production of more efficient turbines without the increase in NO_x normally associated with higher firing temperatures.

Electric motors were not commonly used with larger, reciprocating compressors until technology enabled high horsepower, high voltage, variable speed, motor-driven systems. Although this technology emerged in the 1980s (and was implemented by some operators as early as 1982), modern large horsepower synchronous and induction electric motors and variable frequency drive (VFD) systems became more widely used in the late 1990s.

Reciprocating compressor units made a resurgence in the 1990s for low flow applications with the introduction of a new class of high speed reciprocating compressor units made possible by advances in technology and reductions in cost. High speed reciprocating engines (specifically, internal combustion engines), which offered higher thermal efficiencies and improved fuel economy than their low speed predecessors, were developed to match these compressors. See Figure 5.

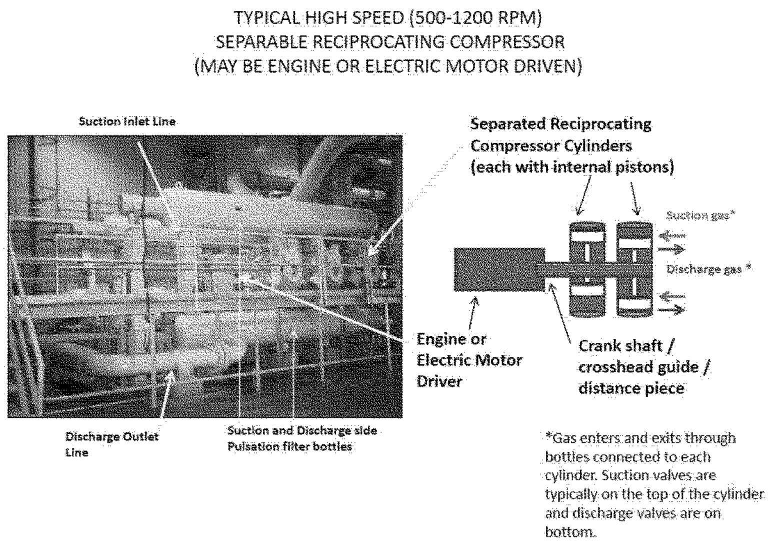

Figure 5. High Speed Separable Reciprocating Compressor

Nonetheless, when these high speed engines were combined with high speed reciprocating compressors (which had a lower efficiency than low speed reciprocating compressors), the overall net compressor unit efficiency actually was lower than vintage (low speed engine/low speed compressor) reciprocating compressor units.

In addition, technology advances allowed automation and communications systems to operate pipeline facilities remotely from a central gas control center, thereby reducing pipelines' operation and maintenance (O&M) costs. This advanced technology has allowed pipeline companies to communicate with compressor stations more quickly and to respond to changes in system flow more effectively.

Appendix B provides greater detail on compressor technology. Table B-1 compares and contrasts the design efficiencies and attributes of the compressor units in service today.

B. SUMMARY OF HISTORICAL EFFICIENCY DEVELOPMENTS

Over time, pipeline companies have incorporated various technological advances that have permitted significant gains in pipeline hydraulic efficiency, prime mover thermal efficiency and compressor efficiency, as well as improvements in flow control, reliability and emissions control. Pipeline companies have tried to balance installing the most efficient equipment with the willingness of customers to pay for the state-of-the-art technology. This challenge has been complicated by the continuous expansion of the pipeline system to meet a growing customer base. The result is a myriad of pipeline technologies (diameter, steel strength, and operating pressure) and compressor station technologies (compressors, prime movers, and piping connected to the compressor units), all of different vintages, distributed throughout today's pipeline network.

As shown in the following table, pipeline companies have used increasingly larger diameter pipeline and higher pressures to improve the hydraulic efficiency of the system. Since 1940, maximum line pipe diameters of newly built pipelines have doubled from 24 inches to 48 inches, while the MAOP has more than doubled from 720 psig (pounds per square inch, gauge pressure) to 1750 psig or higher. This has been achieved through the development of economic, high strength steels, enabling pipelines to be built economically and safely operated at higher pressure/stress levels. Advances in high strength steel continue to this day. Improved quality control in the manufacturing, transportation, installation and testing of new pipe has allowed the operating pressure of some new pipe installations to increase from 72 percent to 80 percent of its specified maximum yield strength (SMYS).

Table 1: Changing Pipeline Design and Construction Parameters

Decade of Construction	Available Maximum Diameter	Available Maximum Operating Pressure	Available Pipeline Steel Yield Strength (psi)	Available Maximum Stress Levels (% of SMYS)	Available Internal Coating	Piggable Pipelines
<1940	24"	720 psig	42,000	72%	No	No
40-49	28"	720 psig	46,000	72%	No	No
50-59	30"	860 psig	52,000	72%	No	No
60-69	36"	860 psig	60,000	72%	No	No
70-79	36"	1020 psig	65,000	72%	No	No
80-89	42"	1440 psig	70,000	72%	Yes	Yes
90-99	42"	1440 psig	80,000	72%	Yes	Yes
00-09	48"	1600 psig	100,000	72%	Yes	Yes
Present	48"	1750 psig	100,000	80%, 72%	Yes	Yes

Fuel rates for the newest generation of very large gas turbines (>20,000 hp) have improved 32.5 percent, from 9426 Btu/hp-hr to 6362 Btu/hp-hr (an increase in thermal efficiency improvement from 27 percent to 40 percent). Smaller units have improved as well as demonstrated in Solar Turbine's Gas Turbine Efficiency Improvements chart below, Figure 6.

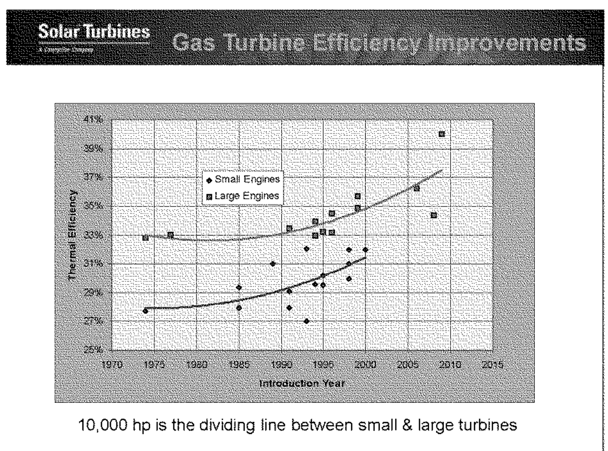

Figure 6. Gas Turbine Efficiency Improvements

Solar Turbine Titan 250 Gas Turbine; Gas Electric Partnership, February 2010

The efficiency of the newest generation of centrifugal compressors, powered by these gas turbines, has increased from 75 percent to 88 percent. As a result of these advances, the overall design efficiency of a gas turbine-driven centrifugal compressor unit now is close to 33 percent, which is a 50 percent improvement over the machines deployed 20 years ago. Advances in centrifugal compressor efficiency have been aided by computational fluid dynamic analysis, intensive testing, and the use of impellers with three-dimensional geometry to assist in aerodynamic flow passage design.

In addition, there have been advances in reciprocating engine technology. Since 1995, the efficiency of newer and most sophisticated gas-fired reciprocating engines has increased by four percent (from 42 to 46 percent peak thermal efficiency at 100 percent load) while at the same time the effectiveness of emissions control systems has improved to meet increasingly stringent NO_x requirements. Higher speed reciprocating compressors have provided a means of compressing more gas and thereby achieving higher throughput at a lower installed cost. Many pipeline companies now are designing systems in which modern electric motors (90 to 95 percent thermal efficiency at the site),[12] or reciprocating engines (30 to 43 percent thermal efficiency) are used to power high horsepower, low speed, reciprocating compressors (80 to 92 percent compressor efficiency) to improve overall compressor unit efficiency.

One more development affecting efficiency has been the surge in construction of natural gas storage. Because it generally is more economical in providing short-term delivery or receipt capacity than expanding pipeline capacity, storage has become an increasingly important way for pipeline companies to meet customers' peak day capacity requirements and to accommodate outages. By using storage to augment baseload pipeline capacity and help to moderate rapidly varying demand requirements, pipelines can be operated more efficiently. Producers, suppliers and customers use storage to balance short-term demand swings during the day and other changes during periods that do not correspond to the traditional heating season pattern.

[12] When source energy losses are considered, electric motors may achieve 25 to 46 percent thermal efficiency.

C. LEGISLATIVE AND REGULATORY DEVELOPMENTS AFFECTING EFFICIENCY

Along with advances in pipeline and compression technology, legislative and regulatory initiatives also have affected the incentives for improving efficiency in the interstate natural gas transportation industry. The wellhead natural gas decontrol enacted by the Congress in 1978 and 1989 created a competitive natural gas commodity market that led to the emergence of large supply and market hubs. Unbundling of pipeline companies' natural gas sales and transportation services, implemented by the FERC through Order 436, *et al.*,[13] further contributed to a competitive interstate natural gas transportation system. These developments made customers less dependent on a single pipeline company for their entire gas supply, and enabled them to satisfy their need for gas supply without contracting for transportation capacity all the way back to the wellhead.

The FERC's pro-competitive policies also have affected how pipeline companies invest in equipment or processes that may increase transportation efficiency. In the past, local distribution companies and other large pipeline customers committed to long-term contracts (15 to 20 years), making it feasible to design and build in long-term transportation efficiency investments under rates that afforded the pipeline company a reasonable opportunity to recover its investment plus an adequate rate of return on the investment. Today, by contrast, pipeline customers are less apt to commit to long-term contracts on existing systems. Further, as a result of pipeline-on-pipeline competition, many pipelines have to discount heavily to attract and retain long-term customers. Pipeline companies face cost recovery risks, even on new Greenfield projects, after the initial contract terms expire. Moreover, large customers have the market power to force pipeline companies to compete on the basis of price to build new or expanded pipeline capacity to meet new demand. In that price-competitive context, the feasibility of discretionary system-wide transportation efficiency improvements is dependent on the willingness and ability of customers to commit to rate levels that will fund the improvements

[13] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, Regs. Preambles 1982-85, FERC Stats. & Regs. ¶ 30,665 (1985), *order on reh'g*, Order No. 436-A, Regs. Preambles 1982-85, FERC Stats. & Regs. ¶ 30,675 (1985), *order on reh'g*; Order No. 436-B, Regs. Preambles 1986-90, FERC Stats. & Regs. ¶ 30,688, *order on reh'g*, Order No. 436-C, 34 FERC ¶ 61,404, *order on reh'g*, Order No. 436-D, 34 FERC ¶ 61,405, *order on reh'g*; Order No. 436-E, 34 FERC ¶ 61,403 (1986), *aff'd in part and vacated and remanded in part sub nom. Associated Gas Distribs. v. FERC*, 824 F.2d 981 (D.C. Cir. 1987).

over the long term, or the ability of the pipeline company to recover its investment costs through cost savings or increased throughput.

In addition, customers' increased use of capacity rights made available under FERC's Orders 636 and 637 *et al.*[14] may require pipeline companies to operate their systems differently, and less efficiently, than contemplated by the original system design. For example, meeting multiple demand requirements at different delivery points may require a pipeline to maintain higher pressures, alter flow rates or impose larger turndown requirements[15] on compressor stations, producing less efficient compressor operation than envisioned under the design conditions. In addition, a decline in baseload demand from industrial customers and a dramatic growth in the utilization of natural gas-powered electric power generators (typically dispatched to meet midrange and peaking electric loads) make the pipeline flow requirements highly variable compared to historically more constant demand loads. The electric generation load has, in some cases, created a summer demand peak requiring more fuel use. On many pipelines, steady baseload demand has been replaced by less predictable, day-to-day, load swings. Notwithstanding these new operational challenges, pipeline companies have adapted to wide variations in supply and demand patterns through off-design operations that often require, for example, more frequent starting and stopping of compressors with little notice. While such off-design operation results in higher fuel use, interstate gas pipelines can serve peaking electric generators by ramping up pipeline compressors quickly (either gas turbine, engine or motor-driven) and use line pack to meet rapidly changing load swings.

[14] Specifically, customer rights related to flexible receipt and delivery points, segmentation of capacity to multiple points, and capacity release to both primary and alternate points. *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs., Regulations Preambles Jan. 1991 – June 1996 ¶ 30,939, *on reh'g*, Order No. 636-A, FERC Stats. & Regs., Regulations Preambles Jan. 1991 - June 1996 ¶ 30,950, *on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *on reh'g*, 62 FERC ¶ 61,007 (1993), *aff'd in part, vacated and remanded in part, United Dist. Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997); *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. ¶ 31,091, *clarified*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *aff'd in part and remanded in part sub nom. Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002).

[15] Turndown refers to how flexible a compressor is at different operating conditions (flow and pressure). The greater the turndown capability of the compressor unit, the greater the flexibility the compressor unit has to operate under different flow and pressure conditions.

Federal, state and local environmental and siting regulations often affect the ability of a pipeline company to maximize design efficiency. Pipeline companies design their systems based on the optimal balance between pipeline and compression and the type of compressor unit that will best serve the project. Yet, these decisions often are impacted by environmental regulations that limit the emissions of air pollutants at compressor sites. As illustrated in Appendix B, Table B-1, different compressors and prime movers excel under different design scenarios and operating conditions. Yet, if the pipeline is in an area with strict emissions limits (such as a non-attainment area), which limits additional emissions greatly, the pipeline company may not be able to install a compressor driven by either a gas-powered reciprocating engine or a gas turbine, even if the gas-powered compressor would have been the most efficient solution under the circumstances. The pipeline company may need to relocate compression to a less than optimal area outside of the non-attainment area, install an electric motor to drive a compressor (which would have no emissions at the site), and/or install larger diameter pipeline in lieu of additional compression (which may require additional right-of-ways and will be much costlier than compression). These choices actually may push the pipeline company to purchasing decisions that reduce both economic and transportation efficiency. For example, suboptimal placement of a compressor unit may decrease transportation efficiency and drive up fuel costs. Further, installing an electric motor-driven compressor in a remote area far from the electric grid is an unattractive option, particularly due to the time and cost it would take to interconnect to the power grid and issues related to the reliability of the power supply.

Similarly, modifying, upgrading or retrofitting an existing pipeline compressor station may trigger the EPA's New Source Review (NSR). The NSR requires a pipeline company to apply for a permit in advance of modification and (1) to install BACT if the station is a "major source" in an attainment area or (2) to install controls to meet the Lowest Achievable Emission Rate in a non-attainment area. These control requirements often require the installation of add-on controls, which cause the compressor to run less efficiently. Further, as technology improves, EPA continues to require greater control technology and it is not always clear whether the pipeline's modification designs will meet EPA's control requirements without major changes to equipment. With such uncertainty, pipelines companies often are hesitant to modify compressors since the modification may trigger the NSR, which applies regardless of whether the station is in a non-attainment area.

EPA's proposed rule establishing national emissions standards for hazardous air pollutants (NESHAP) for reciprocating internal combustion engines (RICE) also illustrates how regulatory requirements may compromise pipeline efficiency. The proposed rule would limit the carbon monoxide and formaldehyde emissions from engines commonly used at natural gas compressor stations. The only way to assure compliance with the proposed limits would be to install post-combustion catalytic control equipment. This equipment degrades engine efficiency by requiring the engine to operate at a higher fuel-to-air ratio, causing the engine to burn more fuel than necessary and thus operate less efficiently. The efficiency degradation could be as much as one to two percent per unit which, measured over the entire system, could be quite significant.

Additionally, uncertainty over the timing and content of pending and proposed climate change legislation and regulation deters investment in efficiency improvements aimed at reducing GHG emissions. Pipelines are concerned that investments made today to achieve incremental improvements in efficiency could be rendered obsolete if final climate change legislation or regulation compels a pipeline company to make a wholesale change in compressor technology. Additionally, should the EPA be prescriptive in what it considers BACT for regulating GHGs under the Clean Air Act, BACT compliance may limit the efficiency improvement options available when a pipeline company installs a new compressor or modifies an existing one.

Further, the increased use of renewable energy sources may affect pipeline operations. Many industry analysts anticipate that natural gas-powered electric generators will be called upon to fill the gap created by the intermittent nature of solar and wind power and the current lack of commercialized methods to store electricity from these energy sources. This, in turn, could create new demand for natural gas transportation and storage services that can respond quickly and reliably in providing intermittent fuel for these gas-powered electric generators. Natural gas pipeline transportation offers tremendous flexibility and the capability to operate at off-design conditions enabling power companies to use gas-fired generation to meet their customers' load when intermittent supplies wane. While operating at off-design conditions to bring compressors on and off line quickly (to back up the intermittent renewable energy supply) likely increases fuel use, the interstate natural gas pipeline system's capability to operate so flexibly is a great advantage in meeting the Nation's diverse energy needs.

In summary, pipeline companies have been proactive in identifying and incorporating ways to improve pipeline system operating efficiencies while at the same time providing reliable service to an increasingly complex and variable customer base. Pipeline companies must weigh decisions to maximize transportation efficiency with competing considerations, such as the ability to meet customer contractual requirements and market demands, the ability to recover the cost of the investment, compliance with existing and pending environmental regulations and legislation, and landowner siting accommodations, that at times lessen or eliminate a pipeline company's ability to make such efficiency investments.

D. RESEARCH AND DEVELOPMENT

Pipeline companies are engaged in research and development (R&D) either themselves or through organizations such as the Gas Machinery Research Council (GMRC), Pipeline Research Council International (PRCI), Pipeline Simulation Interest Group (PSIG), Gas Technology Institute (GTI), Southwest Research Institute (SwRI) and the American Society of Mechanical Engineers (ASME). Through these organizations, pipeline companies can pool their resources and undertake R&D on a relatively economical basis.

Pipeline companies have long worked with original equipment manufacturers (OEMs) such as Cameron, Solar Turbines, General Electric, Dresser-Rand, Rolls-Royce, Ariel and Caterpillar who develop and deploy advances in thermal and compressor efficiency and thereby reduce engine fuel consumption, lower maintenance costs and downtime, and increase availability. Pipeline companies have installed prototype units to assist OEMs in testing and commercializing new products. For example, dry low emission (DLE) technology has been developed for gas turbines in order to reduce high NO_x production due to higher firing temperatures. DLE technology makes the compressor units much more complex and costly to buy, operate and maintain, so the improvement must be weighed against the associated cost. Nevertheless, due to R&D efforts focused on these technologies, modern gas turbines achieve significantly lower air emissions (e.g., NO_x, CO_2) than their predecessors.

Pipeline companies also have worked with material suppliers and contractors, such as steel mills, coating shops and welding companies, to advance pipeline and coating material technology and construction techniques. This partnership has produced high strength steels, new welding techniques, and internal and exterior coatings. Finally, new operations simulation software enables pipeline companies to predict and optimize the combination of compressor units that will consume the least fuel to transport a given quantity of gas to meet an anticipated market demand. Appendix E highlights a sample of research studies on various topics such as metering, turbine and engine retrofit technology, compressor technology, and corrosion and leak detection.

In the following sections, this report will examine the considerations related to economic and transportation efficiency in the design, operation and maintenance of natural gas pipelines. This historical review has shown that the current United States and Canadian pipeline network is composed of many technologies representing different eras of pipeline development. Each pipeline system is unique; each pipeline and each of its compressors and prime movers is a product of its design era, its origins, the additions made over time, and the market it serves. A "one-size-fits all" solution to implementing cost effective energy investment and efficiency improvement would not be practical.

DESIGNING PIPELINES FOR EFFICIENCY

Efficient pipeline design must consider many competing factors that influence economic and transportation efficiency. This section describes the major decisions confronted by pipeline planning engineers and the pipeline officers that ultimately must justify the capital investment regarding the selection of pipeline diameter and compression requirements, compressor unit components, and how the pipeline company weighs the competing demands of investing in the most efficient infrastructure with serving its customers at competitive rates.

A. PIPELINE SYSTEM DESIGN

The greatest opportunity for maximizing both the economic and transportation efficiencies of a pipeline system is in the initial design and construction phase of a major pipeline facility. Overall system transportation efficiency will be determined during the design phase by a combination of the expected hydraulic efficiency of the pipeline and the efficiency of the compressor station components. The initial design normally is based on peak day contractual commitments plus an accommodation for future demand that can be reliably forecast.

The pipeline company selects its components and equipment based on a balance of reliability and flexibility. Since an interstate pipeline is a long-lived asset, wholesale replacement of an existing pipeline system with new facilities is not economic. The choices made during the initial design significantly limit the ability of a pipeline company to enhance transportation efficiency later by replacing individual system components or by modifying the pipeline system. Consequently, subsequent modifications to accommodate shifting supply zones, changes in customer demand and technological improvements must be integrated into the existing system and must complement rather than replace the initial design.

B. PIPELINE VERSUS COMPRESSOR STATION DESIGN

During the initial system design, or during any system expansion or other major construction project, pipeline companies consider the optimum combination of pipeline diameter, operating pressure, and compression facilities needed for a given system flow rate necessary to meet projected contractual demand. From a capital perspective, the installation of compression typically is significantly less costly than the installation of long miles of pipeline. As a rule of thumb, in a new pipeline design, a pipeline company can spend two to four times more initial capital on pipeline than on compression to achieve the same delivered cost of gas. Still, in choosing compression over pipeline to achieve a given deliverability, a pipeline designer also is opting for typically higher operating and maintenance costs (along with associated labor) as well as increased fuel usage. These operating and maintenance costs increase as the equipment ages.

Pipeline system design engineers explicitly calculate the trade-off between the costs of a larger diameter pipeline (with less compression) versus the initial capital and life cycle[16] operating and maintenance costs of supplemental compression to achieve a desired flow rate. The analysis of a given investment to improve either hydraulic or thermal efficiency must measure the anticipated value of the cumulative fuel savings over the useful life of the investment. Pipeline companies also must factor in the future demand for the pipeline's service and the length of initial contracts in order to determine whether there will be a reasonable opportunity to recover investment costs.

To determine the optimum combination of pipeline diameter and horsepower (i.e., compression) requirements, pipeline project designers use "J Curves", which compare the delivered cost of fuel to the cost of pipe. In the J Curves shown in Figure 7, the pipeline company considered a range of pipeline diameters from 20-inch to 42-inch pipe and various MAOP values. While the 36-inch diameter pipeline would be preferable, the pipeline designer may select a larger diameter pipeline or choose to operate the pipeline at a higher pressure if future growth is reasonably predictable. Yet, naturally, the larger pipeline would be more expensive. Thus, the choice of pipeline diameter and operating pressure are based on an assumed flow rate and affect delivered cost.

Another factor that affects the balance between pipeline diameter and compression is the non-linear relationship between flow and fuel (due to flow losses – see Appendix A). As shown in Figure 8 (using actual data for the Tennessee Gas Pipeline System), doubling the flow from 700 to 1400 MMcf/d quadruples total fuel usage from 9 MMcf/d to 35 MMcf/d. The disproportionate increase in fuel consumption at higher flow rates does not mean that the

[16] Life cycle costing is the evaluation of an investment by considering the costs and benefits over its entire serviceable life.

compression operation becomes less efficient. The fuel consumption indicates that the pipeline is highly utilized and is required to transport more gas to meet demand.

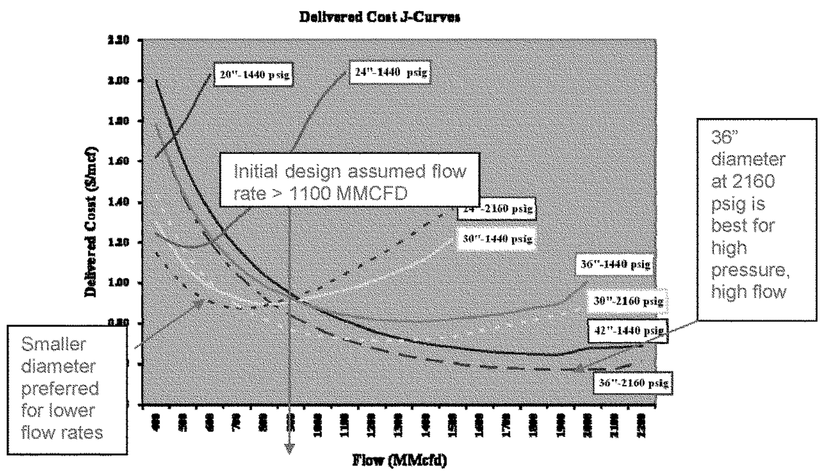

Figure 7. Example J Curves for Pipeline Delivered Cost

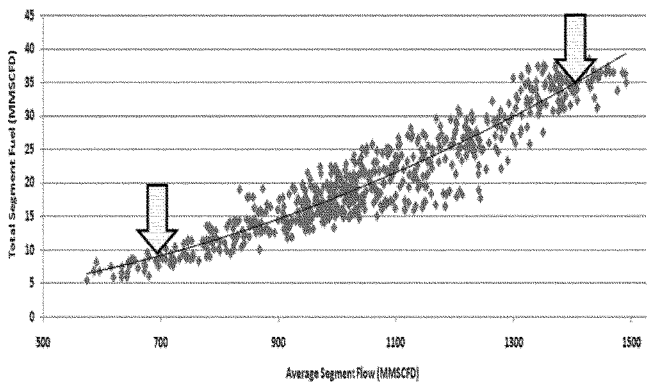

Figure 8. Exponential Fuel Consumption Resulting From Increased Flow
Tennessee Gas Pipeline; Gas Electric Partnership Presentation, February 2010

In addition to choosing pipeline diameter, a pipeline company designing a facility considers whether to install internally coated pipeline. The real benefit of internal coating occurs when the pipeline is experiencing high flow rates because it reduces friction in the pipeline, and, consequently, reduces the amount of horsepower needed to maintain pressure for a given throughput. Because it involves a substantial expense, internal coating is not effective in many circumstances. Assuming that rates support the investment, internally coated pipeline could be used for future expansions, pipeline replacements or as a trade-off to compressor horsepower. Further information on internal pipe coating is provided in Appendix C.

The location and spacing of compressor stations is another important factor in overall pipeline transportation efficiency. Appendix D illustrates how station location can be used to reduce cost while optimizing efficiency. Environmental and landowner considerations, however, may dictate compressor selection and spacing that is less than optimal from an engineering and efficiency perspective.

C. COMPRESSOR SELECTION

After a pipeline company determines the optimal balance between pipeline specifications and horsepower requirements, it selects the compressor units that best meet its load profile and operating needs. A number of considerations go into the selection including: (1) forecasted operating conditions, (2) the unit's air emissions to ensure compliance with air quality regulations, (3) the upfront, installed costs, (4) the projected operating costs, (5) the projected maintenance costs and availability of replacement parts, (6) the unit's compatibility with the existing compressor fleet, (7) the overall efficiency of the compressor unit (i.e., a combination of the thermal efficiency of the prime mover and the compression efficiency of the compressors themselves), (8) the reliability of compressor unit components, and (9) the expertise of pipeline personnel with particular equipment.

While pipelines are designed to operate at peak hydraulic efficiency under high load conditions, many pipelines operate at low load conditions for several months of the year. Pipeline designers therefore select compressor units that best allow a pipeline to meet peak day contractual commitments while achieving an acceptable efficiency level when operating off peak.

To illustrate the difficulty of maintaining high efficiency with wide variability requirements in flow and compression, Figure 9 depicts the seasonal load variability of a typical mainline pipeline system over a five year period from 2005 through 2009. Monthly average throughput varied significantly over this period. Throughput was close to 600,000 Dth/d during the winter months, yet dropped to roughly one third of this level in other months. The pipeline company can meet the flow requirements for eight months of the year by running minimal amounts of compression. Because additional horsepower is required only from November through March, the pipeline company may select compressor units with the lowest cost that provide the greatest flexibility. Compressor units with a flat efficiency curve over a broad range of operational points also may be suitable, but efficiency may not be as a great when operated outside of this range at peak flow. This example shows the difficulty in justifying an investment in the most fuel efficient prime mover and compressor package for a particularly high flow design point (which may be more costly as well), if the pipeline company anticipates that it will operate at this design flow for only a small portion of the year.

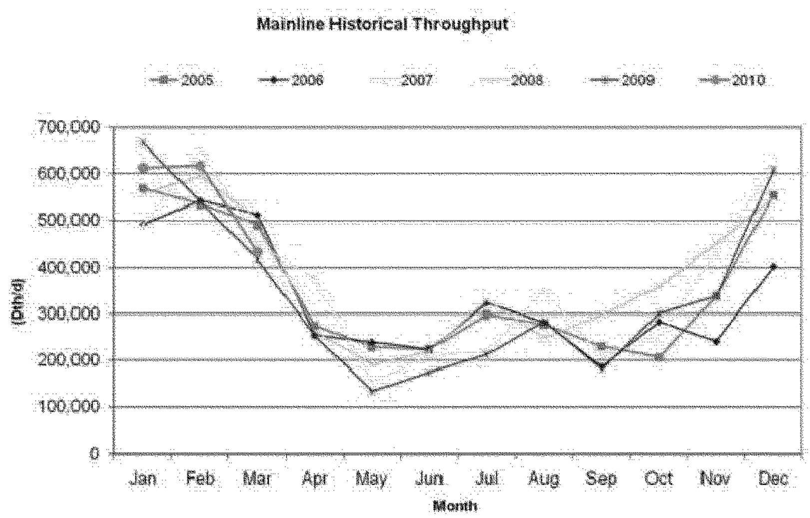

Figure 9. Five Year Daily Average Throughput (Dth/d) Variations by Month on U.S. Pipeline

Another design decision that can affect pipeline efficiency is whether to install one or more large units per compressor station versus several smaller units. To address variable market area customer demands while maintaining high operational efficiency, pipeline companies sometimes select multiple, smaller compressor units that can be switched on and off to meet throughput and pressure needs.

Assuming the same configuration and location, two smaller compressor units will have a higher cost per horsepower compared to a larger unit due to economies of scale. One fully-loaded, larger unit will be more fuel efficient and will cost less than two smaller equivalent sized units. By contrast, one fully-loaded, smaller unit will be more fuel efficient and offer more flexibility than one partially-loaded, larger unit. Similarly, operating multiple, smaller compressors can achieve better overall fuel efficiency than a single larger compressor if the pipeline operates predominately at less than maximum throughput. The fuel savings, however, may not outweigh the installation costs of additional smaller units.

To illustrate this point, one pipeline company recently considered adding additional compression at one of its stations. Figure 10, below, shows the vast range of operating conditions that occurred at the compressor station in question. The pipeline company had a choice. It either could install a single larger centrifugal compressor with a high design efficiency at full-flow conditions (86 percent) but with poor efficiency at less than ideal flow conditions (77 percent), or it could install multiple smaller units that are not as efficient as larger units under full-load conditions, but provide the operator greater flexibility to meet the demand variability of its customers. In this case, the pipeline company chose the latter. Even though the single, larger unit was less expensive and had a higher design efficiency than the combination of the smaller units, in actual operation, the smaller units will achieve higher fuel efficiency and offer greater flexibility based on the station's operating conditions. Another pipeline company, with different load variability, may select a different compressor mix, either in the number of compressors or the type of compressor.

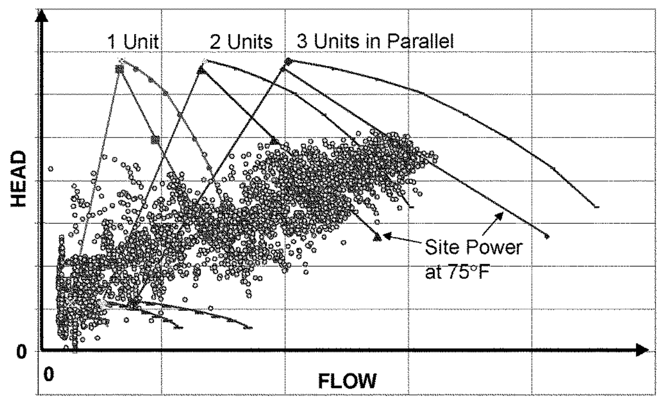

Figure 10. Depiction of the Scheduling of Multiple Compressor Units to Adjust for Actual Operating Conditions at a Pipeline Compressor Station

In addition to the number and size of compressors, pipeline companies also make choices when selecting types of compressors. There are inherent design tradeoffs between reciprocating compressors and centrifugal compressors, and the operating parameters and range of each technology vary greatly. In general, reciprocating compressors are more effective in situations with varying pressure ratios (i.e., where the ratio of discharge to suction varies substantially), while centrifugal compressors are more effective in situations with some flow variability and relatively constant pressure ratios. Therefore, for a pipeline with variable customer flow requirements, but fairly constant pressure conditions, a centrifugal compressor is the preferred technology. On the other hand, where a pipeline needs to respond to wide ranging pressure ratio conditions (given large changes in suction or discharge pressure or both), reciprocating compressors perform more efficiently than centrifugal compressors. Regardless of the type of compressor, when a pipeline operates outside the design parameters of the unit (either in terms of pressure ratio or flows), the compressor will use more fuel than it would have at design conditions because all compressors are less efficient when operating away from their optimum design conditions (either in terms of pressure ratio or flows). See Appendix B, Table B-1 for a comparison of advantages, disadvantages and efficiency ranges for each pipeline compressor technology.

D. PRIME MOVER SELECTION

Three primary types of prime movers (drivers) are used in pipeline applications: reciprocating gas engines, gas turbines and electric motors. The principal attributes and drawbacks of each are described below.

Reciprocating Gas Engines: Similar to an internal combustion engine used in a motor vehicle, the reciprocating gas engine uses a chamber, filled with natural gas, to drive a piston. The gas is ignited and combusted to cause the piston to move. Slow low speed and high speed engines are matched with compressors of corresponding speed. Legacy internal combustion, slow speed, engines have significantly less sophisticated controls and lower fuel efficiencies than state-of-the-art engines. While today's reciprocating engines are quite efficient, they do have power limitations and can have high vibration issues that affect reliability. Certain components may be high maintenance, and the engine units require ample spare parts and service contracts as back up.

Gas Turbines: Gas turbines rely on the hot exhaust gas produced from the discharge of a gas generator to drive a power turbine. The shaft output power from the power turbine is used to drive the pipeline gas compressor. Two types of turbine are used: (1) the aeroderivative engine, which is based on gas turbines developed for the aviation industry (the hot exhaust gas is used to push the aircraft through the air rather than through a power turbine) and (2) the industrial turbine which is designed specifically for industrial use. Aviation industry developments have contributed to the continual improvement in performance (in terms of power and efficiency) of both aeroderivative and industrial gas turbines.

Electric Motors: Electric motors are more reliable and more efficient as stand-alone pieces of equipment than either reciprocating engines or gas turbines. They are able to ramp up quicker than reciprocating engines or gas turbines. They also have an advantage where air quality regulations are an issue because they do not emit NO_x and CO_2 at the point of use. There are a number of competing factors, however, that affect the suitability of using an electric motor as the prime mover for a pipeline compressor. One is the requirement for variable speed and the resulting relatively high cost of an electric motor, variable frequency drive, auxiliary equipment, and the training and maintenance needed to support them. The availability and proximity of a suitable electric power supply or substation is also an issue, because it can be costly to install a new interconnecting electric power transmission line, and it may be difficult to obtain the necessary regulatory approvals. Reliability of the electric power transmission grid (overhead transmission lines are susceptible to damage in severe weather conditions), availability and cost of power from the local distribution company, and the obligation to pay electric demand charges even when the unit is not running are additional factors when considering installation of an electric motor. In addition, looking ahead to GHG regulations, the carbon footprint advantage that electric motors have over the reciprocating engines and gas turbines at the site is offset by high energy losses in the transmission of electric power and the higher carbon footprint of the electric generation power source (e.g., electricity from coal).

The pipeline company's compressor selection (centrifugal or reciprocating) usually dictates the choice of the prime mover (gas turbine, reciprocating engine, or electric motor). Natural gas-powered reciprocating engines generally are limited to driving reciprocating compressors. Natural gas-powered turbines generally are limited to driving centrifugal compressors. Electric motors may be used with either compressor technology, although pipeline companies have begun using electric motors to power centrifugal compressors on a more widespread basis than reciprocating compressors.

The upfront cost of component parts is an important consideration for pipelines when selecting compressors. Life cycle and avoided costs, where applicable, also are factors to be considered, however. Low speed compressor units powered by reciprocating engines are the most expensive option in terms of installation cost ($/hp). Gas-fired combustion turbines and electric motors have approximately the same installed cost.

E. COMPRESSOR UNIT SELECTION

Pipeline companies select the appropriate equipment for a particular service based on both technical (e.g., flow, pressure ratio, utilization, efficiency) and commercial considerations (e.g., delivered cost, contractual underpinning, etc). The weight given to these criteria varies from pipeline to pipeline or from application to application. What may improve system efficiency or be cost-effective on one pipeline system may not be cost-effective or practical on another system. Therefore, there is no one-size-fits-all efficiency prescription that will yield desired efficiency improvements on all pipeline systems.

The installed cost of a compressor unit may vary significantly depending upon whether it is a Greenfield installation (i.e., a brand new compressor station), an additional compressor unit installed at an existing station, or the replacement of an existing compressor unit with a state-of-the-art unit. Generally, an additional compressor at an existing station is the least expensive option, followed by a state-of-the-art replacement unit; a Greenfield unit is the most expensive option.

Based upon an actual case study, Table 2 below compares the upfront capital cost of various compressors and prime movers for a 14,400 horsepower compressor replacement project in 2010. Typically, installed costs for a mid-sized natural gas compressor powered by a combustion turbine at a Greenfield location is $2,500 to $3,500 per horsepower.

Table 2. Relative Driver / Compressor Cost Comparison for 14,400 Horsepower Compressor Station

	Estimate for Initial Cost on Site				
	Single GT Turbine / Centrifugal Compressor	Multiple GT Turbines / Centrifugal Compressors	Electric Motor / High Speed Reciprocating Compressor	High Speed Engine / Reciprocating Compressor	Slow Speed Engine / Reciprocating Compressor
Total Installed Cost	100%	129%	130%	132%	154%

In this particular case, the pipeline company elected to purchase a slow speed engine/ reciprocating compressor unit, even though it was the most expensive option, because of the potential fuel savings. However, when the price of gas dropped below $7/Dth, this project became less attractive. The project was canceled when gas prices dropped below $4.50/Dth and the load factor of the pipeline dropped approximately 50 percent. The pipeline company is looking for other locations to install the slow speed engines and to allocate the dollars spent.

As illustrated above, initial cost is not the only criterion for selecting a compressor unit. A pipeline company may select a more expensive unit rather than select a lower cost compressor unit for a variety of reasons. For example, a pipeline company may select a more expensive unit if it anticipates that the lower cost unit will operate frequently outside of its optimum operating range and will not provide the operating flexibility the pipeline requires. Also, a pipeline company may select a more expensive unit if the unit provides greater reliability or will be more fuel efficient. In addition, a pipeline company may select a more expensive unit rather than having to install additional equipment to reduce emissions on a lower cost unit, which would increase the overall cost. Furthermore, a pipeline company may be driven to select a more expensive, variable speed, electric motor-driven compressor unit over a less expensive gas-fired compressor unit if it needs to site a compressor in an area with strict emission limits.

OPERATING AND MAINTAINING PIPELINES FOR EFFICIENCY

A. PIPELINE OPERATIONS

Pipeline systems often outlast the transportation market conditions for which they were designed. Notwithstanding the criteria that dictated the original design of a pipeline facility, pipeline companies must adapt their operations in response to changes in delivery markets, supply sources, and possibly new regulatory requirements and business practices.

As a result of FERC's competitive initiatives in Orders 636 and 637, customers have substantial flexibility in how they use pipeline capacity. For example, customers actively use flexible receipt and delivery point rights and the ability to segment their capacity into many transportation paths. They also may nominate transportation quantities at a minimum of four times per day. Gas controllers, who could previously anticipate demand based on weather or typical usage patterns and efficiently "pack the pipeline" to get ahead of events, now must anticipate shipper nominations that reflect day-to-day commodity market conditions, which may have no relation to historic usage patterns on which the pipeline company previously relied. Further, with the increased use of capacity release, the pipelines now transport gas for new customers, who may have very different usage patterns than the original shipper. A pipeline company must schedule customers' transportation requirements, even if the customers' requested schedule/demands do not reflect the most efficient path to move the gas to where it is most needed.

Flow patterns on natural gas pipeline systems have become a lot "peakier." Most pipeline companies with a traditional LDC and industrial customer base designed their pipelines to serve their customers during a winter peak. The pipeline often did not run at full capacity the rest of the year. Now, industrial load has decreased and there are new peaking electric generation customers. For example, peak shaving power generation has created a summer peak load with large swings in flow from morning to afternoon when air conditioning load peaks. This compares to the traditional winter peak heating loads that had two daily peaks, morning and evening. The electric power generators are dispatched with very little notice from their Independent System Operators (ISOs) and, accordingly, the generators provide the pipeline company with very little notice when they need service, thus placing greater demands on the system. As a result, some pipelines recently increased the number of daily nomination windows to 96 (i.e., every 15 minutes) to accommodate power plant demands for no-notice and short-notice service. The rapid response required to meet this demand often causes the compressors to operate outside their optimal efficiency zone, increasing fuel consumption and decreasing thermal efficiency.

In short, due to the obligations to meet customer contractual commitments, real world pipeline performance often falls short of the efficiencies that could be achieved in optimal, steady state conditions. Both the LDC that experiences a cold snap and the electric generator that must be dispatched quickly generally are less concerned about fuel efficiency and more concerned about receiving gas when they need it most.

Pipeline companies employ a number of techniques and procedures to maximize system efficiency while satisfying the level of required customer flexibility and fulfilling contractual commitments:

- Flow simulation software allows transient and real time modeling to help operations that rely on higher linepack. This allows the pipeline to flow gas more efficiently, but requires greater operator vigilance and may require quicker and more frequent shutdowns of compression to avoid over-pressure.
- Shortening the outage time of high efficiency equipment. When high efficiency equipment is out of service (either planned or unplanned), the pipeline company either uses less efficient back-up equipment, or else runs the system less efficiently by increasing the load on downstream compressors. Outage times can be reduced significantly by bringing high efficiency equipment back on line sooner. This can be accomplished, for example, by paying overtime to have maintenance staff work longer hours or weekends, or by paying a premium to have OEMs expedite repair work.
- Consistent with the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's (PHMSA's) regulations, pipeline companies may seek authority to increase their pipeline's MAOP to increase throughput and thereby reduce

compressor fuel usage. Increasing the MAOP increases the pipeline's system transportation capacity and efficiency.[17]

B. PIPELINE MAINTENANCE AND RETROFIT OPPORTUNITIES

Pipeline maintenance has evolved over time, from fixing broken components to preventive maintenance that avoids equipment failure, to predictive maintenance that uses sophisticated data collection and interpretation technology to prioritize maintenance based on computerized analysis. Innovations that the pipeline industry has adopted as best practices prevent damage to the system, ensure reliability and safety, and maximize component life and operating efficiency. This has helped reduce the outage time and increase the availability of high efficiency equipment.

Pipeline companies monitor their systems in a variety of ways to determine if the system is running efficiently, and to establish the optimum maintenance and repair schedule. For example, companies regularly pig lines to remove liquid and solid impurities or obstructions that increase friction and reduce throughput capacity. Pipeline companies launch instruments so-called "smart pigs" to look for potential problems such as metal loss, wall deformations, cracks, and corrosion. This avoids taking a pipeline segment out of service, which would result in less efficient operation. When new connections are need, a procedure known as "hot tapping" allows the work to be conducted without removing the line from service.

Pipeline companies routinely maintain and replace wearable parts such as compressor valves. Compressor valve failures are the single largest cause of unscheduled downtime and maintenance at a reciprocating compressor station. The primary reason that pipeline companies shut down reciprocating compressors, whether scheduled or unscheduled, is to replace a compressor valve. Pipeline companies often match certain valve types with compressor types to create the best seal. There are trade-offs between valve types such as durability, efficiency, maintenance requirements, and cost. Due to advancements in technology, valves now can accommodate compressors that run faster and at higher temperatures. Valves now incorporate condition monitoring systems and other longer life technologies (using semi-active control

[17] One INGAA member company received a special permit from PHMSA to increase the MAOP of its pipeline to 80 percent SMYS rather than 72 percent. This led to an eight to nine percent improvement in transportation efficiency when operated at peak conditions.

methods to reduce impact velocities). If individual components (e.g., compressor poppet valves) improve with new technology, they are incorporated in legacy compressor units.

Pipeline companies also consider the following upgrade or retrofit opportunities:

1. Re-wheeling a centrifugal compressor: This process involves changing the internals of a compressor with an impeller of different diameter or capacity – a bit like changing the gear ratio of an automobile's gearbox to suit different driving conditions. If operating conditions vary significantly from original design conditions, a centrifugal compressor will operate less efficiently and re-wheeling may be economic. These operating conditions sometimes change over a yearly seasonal cycle, while other times the changes are attributable to longer term supply and demand changes (e.g., supply basin depletion).
2. Retrofitting a reciprocating compressor with a new cylinder: Reciprocating compressors can be retrofitted with an improved compressor cylinder design, rated for higher pressures or designed to accommodate new load steps.
3. Advanced pulsation control system designs: The pulsation control system also can be modified at the same time using advanced pulsation controls designed for higher efficiency and less horsepower loss.
4. Engine controls improvement: New engine controls will increase the thermal efficiency of some older reciprocating engines.
5. Electric motor options: Replacing an engine-driven system with an adjustable speed drive electric motor is a retrofit option to accommodate the wide throughput range through speed variation more efficiently than other reciprocating compressor capacity control techniques. This is not commonly done because of limits on the electric motor auxiliary systems or availability and cost of electric power.

C. THE ECONOMICS OF EFFICIENCY UPGRADES

As described above, efficiency opportunities are readily incorporated into new pipeline design. Once built, pipeline companies monitor system components, including compressor stations, to determine whether to repair, modify or, if necessary, replace an entire compressor unit or other system component or otherwise add new technology to improve fuel economy. The industry operates over 6,000 natural gas-fired reciprocating engines, 1,000 natural gas-fired combustion turbines, and 200 electric motors.[18] Yet, just as a car owner does not automatically replace the car or the engine just because a more fuel efficient model has been introduced, a pipeline company cannot justify economically replacing system components to keep in lock step with every state-of-the-art efficiency development.

For example, because the installed costs of natural gas pipeline compressor units have about doubled over the past 15 years, and they are long-lived assets, the cost of a new state-of-the-art replacement compressor unit typically far exceeds the cost of the original unit or the expected fuel savings over a 10 to 15 year period. Accordingly, replacing a legacy unit often is not necessary (since older, properly maintained units can work for many years) or cost-effective even though there is more efficient equipment available. Efficiency upgrade or retrofit decisions can be quite complicated.

Replacing a representative compressor unit with a 10,000 horsepower automated compressor unit with average efficiency may cost $35 million. See Table 3 below. A more efficient compressor unit costs almost $44 million (approximately 25 percent more, and with multiple units to provide greater efficiency the costs jumps upwards of 50 percent more). When gas prices are $4/Dth, it would take 15.6 years to recover the cost of the more efficient compressor, a time period that may not be acceptable to some pipeline companies. Even if the pipeline company wished to invest in the more efficient compressor, the pipeline company may purchase the less expensive, albeit less efficient, alternative if it was competing against other pipelines for business based on the lowest transportation rate.

[18] The actual number of compressor stations is far fewer than the number of engines and motors, because multiple engines or motors typically are grouped at a single compressor station.

Table 3. Compressor Replacement Comparison

Gas Cost	$4.00/Dth		
Compressor size	10,000 hp		
	Heat rate	**Annual Fuel Cost**	**Capital Cost**
Average efficiency	8,000 Btu/hp-hr	$2,242,560	$35,000,000
Best efficiency	6,000 Btu/hp-hr	$1,681,920	$43,750,000
Annual savings		$560,640	$8,750,000
Payout in years if unit operates at 80%		15.6 years	

In order for a pipeline company to recoup the cost of such an investment, a pipeline company either may file a general rate case to recover the cost of the investment in its rates or it may decline to file a rate case and be at risk for recovering those costs either through fuel savings (if the pipeline is on a stated fuel rate) or through additional throughput if the compressor provides relatively cheap expansibility. In either scenario, the investment must be economically justified.

There are a number of reasons why a pipeline company may be hesitant to file to recover these increased costs through a general section 4 rate case. Most prominently, a rate increase likely may be resisted by customers, who will look for rate reductions to offset these cost additions. Further, should the rate increase be too high, customers may take the first opportunity to leave the system for a lower cost pipeline or demand rate discounts (leaving the pipeline company at a risk of under-recovery for those costs) to remain on the system. So, even if a pipeline company could justify its rate increase and charge higher rates, customers with competitive alternatives could demand deep discounts, effectively negating the pipeline company's ability to collect the cost of the efficiency improvement. As discussed above, the competitive market for natural gas transportation has given customers substantial bargaining power. Further, a pipeline company cannot raise the rates charged under negotiated rate contracts to cover the cost of an efficiency improvement through a section 4 filing. The pipeline company only can achieve a rate increase for "recourse" customers—i.e., those paying the generally applicable rate pursuant to Part 284 of FERC's regulations. Moreover, unless the NGA section 4 proposal can be confined to cost recovery for a specific efficiency improvement – which it generally cannot – the section 4 filing opens up all the pipelines' costs and revenues for reevaluation and potential litigation.[19] That is a great disincentive to propose a section 4 rate increase to recover the cost of a discrete efficiency investment in, for example, a replacement compressor, because it effectively turns the economic analysis from that investment into an economic and risk analysis of the overall finances of the pipeline in the section 4 context.

With these caveats in mind, the following cases illustrate some of the calculations involved in the retrofit-replacement-upgrade decision. One INGAA member company considered replacing 16,000 hp with new state-of-the-art internal combustion engines that were 34 percent more efficient (thermal efficiency) than the existing engines at design conditions. The return on investment in fuel savings alone was estimated to require 20 years – much too long to justify this type of investment, which would normally be undertaken on a two to five year return. Other variables affecting the decision included natural gas prices, unit utilization, off-design efficiency and frequency of off-design conditions. Due to these other factors, the efficiency advantage is not always sufficient to justify the upgrade cost. In this case, the pipeline could not justify going forward with the replacement and the project was cancelled.

As with any retrofit/replacement, a pipeline's cost savings or other operational benefits from a newer unit can change if the pipeline's design assumptions change or later prove to be inaccurate. Specifically, a change in the assumed price of natural gas can dramatically affect the fuel saving payback period of a more fuel-efficient compressor. Similarly, if the pipeline company must discount its rates during the payback period greater than expected, the length of the payback period will increase. Further, if the compressor unit is not utilized as assumed because of changes in flow patterns (due to declines in local gas production, change in customer usage, etc.) the payback period for the investment may be much longer than assumed, making the investment not as economic as it should have been. Finally, because pipelines do not operate at design conditions year round, a replaced compressor unit will not always achieve design efficiency if it either operates less than expected or operates at off-peak conditions. A pipeline

[19] *But see Columbia Gulf Transmission Company*, Order on Technical Conference and Proposed Rates, 131 FERC ¶ 61,156 (2010), where the Commission clarified that "pipelines may establish, in limited section 4 filings, an incentive fuel mechanism whereby the pipeline agrees to charge customers fixed fuel rates below the cost-based level the pipeline could otherwise justify, in exchange for a share of the savings that result from the capital improvements made under the incentive mechanism." Order at 61,690.

will not see the savings from the new compressor during the anticipated payback period if the compressor operates less than projected. Similarly, the reliability and estimated maintenance savings for the unit may have to be adjusted to reflect actual operational usage as discussed above. Lower run times result in lower fuel savings. If the design assumptions change prior to installation, the pipeline may decide not to move forward with the replacement/retrofit. If the compressor unit is installed already, the investment obviously will not achieve the desired return on investment and may make the investment uneconomic.

All retrofit options must be evaluated on a case-by-case basis to consider the installed cost, the long-term viability of the station, expected changes in operating conditions and maintenance cost savings. While technologies developed over the last 30 years have created means to improve the efficiency of drivers and compressors, each case must be looked at individually to assess whether the realizable efficiency gains for the expected operational range of the units justify the return on investment.

CONCLUSION

Throughout its history, the interstate pipeline industry has adopted and invested in technology that has produced continuous gains in the overall efficiency of the natural gas pipeline network. Moreover, pipeline companies have responded to the newly competitive environment by implementing additional efficiency gains that have benefited consumers.

The greatest opportunity for maximizing both the economic and transportation efficiencies of a pipeline system is during the initial design and construction stage, when the optimum combination of pipe size, compression, and compressor unit components is chosen to meet projected demand. Once a pipeline has been built, initial design choices limit the ability of the pipeline company to improve transportation efficiency later by replacing individual system components or by modifying the pipeline system. Key considerations in the decision whether to undertake efficiency upgrades are the upfront investment cost, the degree of efficiency to be gained and the cost recovery period. Those calculations in turn depend on the remaining useful life of compressor stations and compressor components, whether new equipment can be incorporated into the existing system, changes in operating conditions and maintenance cost savings, and fuel or other cost savings.

The competitive commercial environment created by the restructuring of wholesale natural gas markets and FERC's open access transportation program has substantially affected the industry's ability to make transportation efficiency investments. In this competitive industry, with pipeline-on-pipeline competition, customers have considerable bargaining power and may be unwilling to pay for efficiency investments that do not have a tangible benefit to them. A pipeline that seeks to recover the investment through a rate increase risks losing customers with competitive alternatives, or risks alienating the customers without alternatives on whom the cost increase would fall. Moreover, as a result of the many additional service options available to customers, many customers are unwilling to commit to the long-term transportation contracts that previously prevailed in the industry, adding additional risk for the pipeline company to recover its capital investments in long-term efficiency improvements.

Throughput levels and off-design operation also can have an important impact on efficiency. When pipelines respond to rapidly shifting customer demand – as they frequently must do today to meet electric power generation load – compressors operate outside of their optimal efficiency zone, increasing fuel consumption and decreasing thermal efficiency. On the other hand, the interstate pipeline industry's ability to ramp up quickly to meet that demand through off-design operation serves the broader energy efficiency interests of the Nation insofar as it meets the need of peaking power plants and renewable (but intermittent) fuel sources.

Stringent environmental regulations also affect efficiency by, for example, influencing route, compressor station siting, and compressor selection (whether the pipeline must install an electric motor-driven compressor versus another selection which may be more efficient under the circumstance). Moreover, uncertainty over the timing and content of proposed climate change regulations affect equipment choices and may deter investment in efficiency improvements.

In sum, each pipeline system is a unique product of its initial design, the technology available at the time of construction, subsequent expansions and modifications, and market and regulatory conditions that shape the demand and expectations of pipeline customers. As a result of this evolution, technologies that may improve efficiency or be cost effective on one system may not be feasible or economic on another. Therefore, a one-size-fits-all approach to transportation efficiency in not practical.

Appendix A: Pipeline Efficiency Background

The transportation efficiency of the pipeline system (η_{sys}) is a combined product of the pipeline hydraulic efficiency ($\eta_{pipeline}$), which measures losses between compressor units, and the compressor unit efficiency ($\eta_{station}$), which includes both driver (thermal) efficiency and compressor efficiency. See Figure A-1.

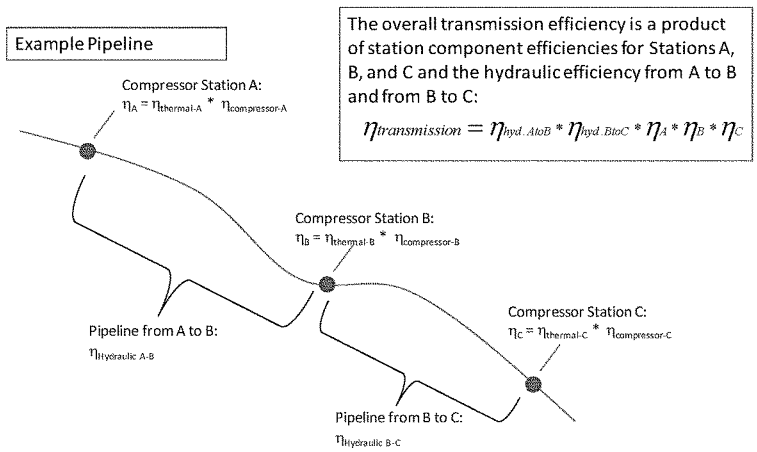

Figure A-1. Example Pipeline Related Efficiencies

Pressure loss along the pipeline is relevant to transportation efficiency because pressure loss will add to the total energy cost of transporting the natural gas, causing actual work to be further from the ideal work used to transport the gas. Higher pressure loss equates to more actual work, which lowers the transportation efficiency. Compressor stations located along the pipeline keep the gas flowing by boosting the pressure of gas to compensate for pressure losses along the line. Higher gas pressure in the flowing pipeline means that the molecules are packed together more tightly and more gas can be transported at the same velocity. Using higher gas pressure and maintaining relatively low velocities is an effective means of increasing hydraulic efficiency (e.g., reducing pressure loss) for the same throughput since the velocity of the gas has a greater influence on pressure loss. The pressure loss is related to friction, the length and diameter of the pipe and the individual pressure losses due to obstructions such as bends, valves or flow meters. Larger diameter pipelines have less surface area per unit of volume than smaller diameter pipelines and, therefore, result in less pressure drop. A smoother internal pipe surface (utilizing internal wall coating) will cause less pressure loss due to friction. Also, the shorter the distance the gas travels and the straighter the pipeline in which it flows, the less the pressure will drop. Correspondingly, fewer obstructions (valves, flow meters, etc.) in the pipeline will reduce pressure loss. Still, pipeline diameter is the biggest single variable in hydraulic efficiency for a given design load. For example, a 24-inch diameter pipeline can move four times the volume of gas as a 12-inch diameter pipeline at a given gas velocity and pressure through the pipe, yet costs only about twice as much to construct and costs virtually the same to operate.

The compressor unit efficiency (a product of the driver and compressor efficiencies) and the pipeline hydraulic efficiency between compressor stations are variables that affect the overall system transportation efficiency. It also is worth noting that there is a minimal pressure drop affecting the compressor station efficiency due to hydraulic losses in the station piping on the suction and discharge sides of the station. When designing its system, a pipeline company tries to optimize hydraulic efficiency through pipeline routing, diameter and operating pressure selections, and unit efficiency through its compressor unit selections (including the engines, turbines, or electric motors that power the compressors).

Appendix B: Compressor Technology Operating Characteristics

Different types of compressors are suited for different applications or services conditions, as depicted in Figure B-1, below. This figure illustrates how reciprocating compressors (single or multi-stage), centrifugal compressors (single or multi-stage) and axial flow compressors at a specified pressure ratio and flow requirement. The y-axis shows the discharge pressure variation considering a constant inlet suction pressure. This effectively represents the range of compression pressure ratios. The x-axis shows the flow rate range for each compressor. Reciprocating compressors are used for high differential pressures and lower flow rates. Multi-stage centrifugal compressors can reach a larger overall flow rate but lower compression ratio compared to multi-stage reciprocating compressors. Axial machines typically are used for very high flow rates with small pressure ratios.

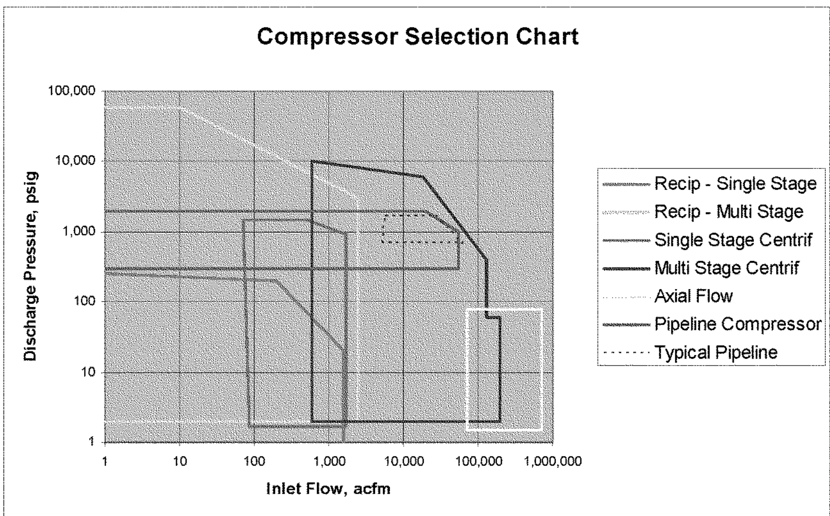

Figure B-1. Compressor Selection Chart

Reciprocating compressors are best suited for low-flow, high pressure ratio scenarios; centrifugal compressors for higher flow low and medium pressure ratio scenarios. Multiple units in series or parallel permit operation of either type at higher flows and pressure ratios.

Compressor technology tradeoffs can be depicted by plotting the efficiency curve against expected operating conditions (expressed in terms of either the expected flow range or pressure ratio range).

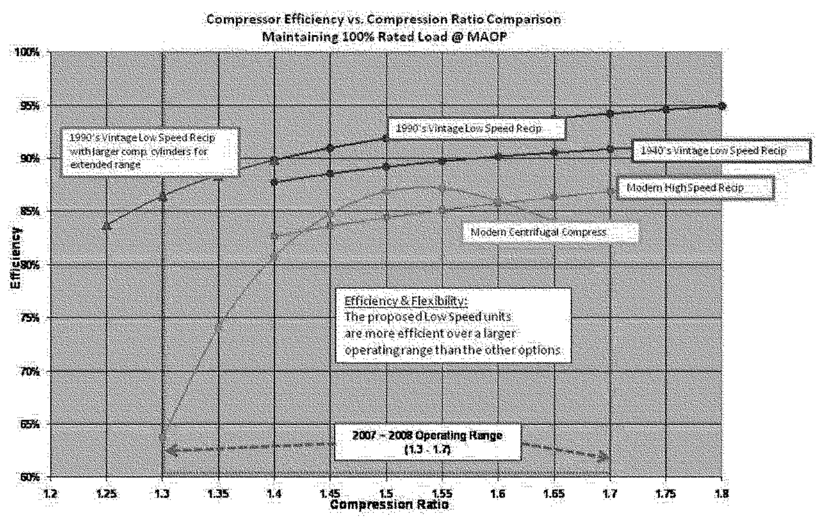

Figure B-2. Compressor Technology Efficiency versus Pressure Ratio

Figure B-2 plots the relationship in terms of efficiency versus compression ratio as the primary purpose of a compressor station is to boost the pressure. The comparison of compressor technologies includes older equipment and modern, high speed reciprocating compressors and centrifugals compressors. The operating parameters and range of each technology vary greatly. The lower speed reciprocating compressors offer a greater efficiency and range for compression ratios compared to modern high speed reciprocating compressors and modern, centrifugal compressors. Still, Figure B-2 assumes a constant flow rate. When operated at a constant speed at lower rates, the efficiency of reciprocating compressors will suffer more severely than the efficiency of centrifugal compressors.

A typical interstate pipeline operates with discharge pressures between 900 to 1750 psig and flows between 400 to 3,000 MMcf/d. For a pipeline with a large flow rate turndown, a centrifugal compressor is the preferred technology from an efficiency standpoint. Lower speed reciprocating compressors offer a greater efficiency and range for large variations in pressure ratio compared to modern high speed reciprocating compressors and modern centrifugal compressors.

When operated at a constant speed and lower flow rate than the design point, reciprocating compressors generally are less efficient than centrifugal compressors. If a pipeline operates outside of the design parameters of the unit (in terms of pressure ratio or flows), the compressor will use greater fuel than at design conditions because of diminished efficiency. This may be cause for modifying the unit. The primary advantage of a reciprocating compressor is its ability to produce high pressure ratios. Such compressors do, however, have high flow limitations. These characteristics make reciprocating compressors particularly desirable in gas gathering or storage injection services, which generally have relatively low flow requirements. Multiple units must be used for high flow service such as mainline interstate pipeline transportation.

Compared to centrifugal compressors, slow speed reciprocating compressors maintain higher efficiency over a wider bandwidth of operating pressure and gas flow conditions (operating range), but they are more costly to install. Reciprocating compressors have a wide range of operational flexibility. The efficiency of these compressors declines at lower flow rates, depending on capacity control options such as such as volume pockets, valve unloaders, and deactivators.

High speed reciprocating compressors (900 to 1200 rpm) often suffer more losses than low speed reciprocating compressors in the cylinder valves and pulsation control system. Lower speed compressors (200 to 400 rpm) tend to be more efficient for the overall compressor system, but may not be driven by the highest efficiency engine due to the age of the equipment. New slow speed reciprocating compressors can be paired with modified or new state-of-the-art reciprocating engines to deliver high compression efficiency within a wide range of operation, albeit at a higher up-front capital cost.

A centrifugal compressor can handle the very high flows that are characteristic of interstate pipelines, but they have pressure ratio limitations. Multi-stage units must be used for high pressure ratio service. Table B-1 briefly summarizes the advantages and disadvantages of reciprocating and centrifugal compressors and their associated prime movers.

Table B-1. Compressor Technology Operating Characteristics at Design Conditions

Prime Mover Technology	Prime Mover Efficiency (percent)	Compressor Type	Compressor Efficiency (percent)	Unit Efficiency (percent)	Advantages	Issues
Reciprocating Compressors						
Legacy slow speed IC engine (200-400 RPM)	27-30	Integral reciprocating	80-92	22-28	–	– Waste heat recovery not economic – Less efficient and higher maintenance cost than legacy slow speed engines
Legacy slow speed + low emissions retrofit (200-400 RPM)	33-35	Integral reciprocating	80-92	26-32	– Compact units	– Waste heat recovery not economic; heat dispersed between exhaust gases and cooling – No longer manufactured
New slow speed IC engine (200-400 RPM)	30-43	Slow speed separable reciprocating	80-92	24-40	– Multi-engine compressor station responds to demand variability more efficiently – Higher partial load efficiencies than turbines – More responsive to varying pressure ratios than centrifugal compressors – Slow speed unit are established infrastructure base with legacy of reliability – May be skid mounted for lower installed cost – Can be variable speed to maintain flexibility	– Larger compressor cylinder design (and more costly) required for similar throughput to high speed machine
Medium speed engine (500-900 RPM)	32-46	Medium speed separable reciprocating	75-90	24-39		– Higher initial unit cost than turbine units – Waste heat recovery not economic – Higher maintenance cost than legacy slow speed engines
High speed recip (900-1200 RPM)	32-43	Separable high speed reciprocating	70-82	22-35		– Lower initial cost than slow speed reciprocating engine – Losses in valves and pulsation bottles are high
Synchronous speed electric motor (360 RPM)	25-46*	Slow speed separable reciprocating	80-92	20-42	– No on-site emissions, simplifies permits	– Requires access to power – Torsional considerations – Speed fixed at 360 RPM (60 Hz)
Centrifugal Compressors						
Legacy gas turbine	22-27	Legacy centrifugal (1950-1980)	71-80	16-22	- only available technology at time for large power	– No longer manufactured
Turbine (< 5 MW)	24-31	Centrifugal	75-88	18-27	– Lower initial cost than reciprocating compressors – Waste Heat concentrated in exhaust gasses; CHP applications if a thermal host is nearby	– Heat recovery for electric generation requires 11+ MW – Lower partial load driver efficiency – Lower offload compressor efficiency
Turbine (5 - 20 MW)	27-36	Centrifugal	75-88	20-32		
Large Turbine (>20 MW)	29-40	Centrifugal	80-88	23-35		
Large Turbine with waste heat recovery (ORC) for electric power generation	33-47	Centrifugal	80-88	26-41	– Electricity may provide revenue stream – Demand for "green" power – Organic Rankine Cycle is more compact with no fluid condensation	– Requires large turbine (11+ MW) – Requires high load factor – Requires close grid access – Possible revenue pass-through requirements – Capital investment requires long-term contract with utility – Regulatory and permit complications. – ORC is less efficient than a steam cycle
Large Turbine with waste heat recovery (steam-based) for electric power generation	34-55	Centrifugal	80-88	26-48	– Electricity may provide revenue stream – Demand for "green" power – Increases efficiency	– Issues listed above for ORC system – Freeze-up in cold weather – Require 24/7 steam operator – Capital investment requires long-term contract with utility
Large Electric motor driven off electrical grid (3600 RPM)	25-46*	Centrifugal	80-88	20-40	– No on-site emissions, simplifies permits – Low capital cost – Low maintenance for motor	– Requires access to power – Cost associated with interconnection and transformer – Power provider may have minimum demand charge – Supply reliability – Generation of electricity at power plant may produce high emissions – Transmission of power also involves high losses especially if distances are great
*Heavily depends on source power generation losses. Electric motor site efficiency can reach 90 to 95 percent efficiency.						
Source: INGAA						

Appendix C: Internally Coated Pipe Comparison

Internally coated pipe is a design option for reducing the pressure losses and increasing hydraulic efficiency of a pipeline system. Internal coating is most beneficial when a pipeline is operating near 100% of design capacity. The fuel savings associated with low flows does not offset the initial cost of the internal coating, which can explain why many variable or lightly loaded pipelines were not internally coated. Its benefit must be weighed against the significant cost of the coating. Figure C-1 compares pressure drop versus flow rate for internally coated and uncoated pipe. In this example, internally coated pipe required less horsepower than uncoated pipe, reducing fuel from 1.627 to 1.452 MMcf/d. The cost of internal coating can vary between \$2 to \$8 per foot, depending on pipeline diameter and the type of coating, e.g., fusion bond epoxy. Additional costs may arise if the pipe mill where the steel was ordered is unable to coat the pipe and the pipeline company must ship the pipe to another manufacturer for coating, possibly resulting in construction delays. Under most circumstances, the cost of replacing old vintage steel pipe with newer, more efficient internally coated pipe would be prohibitive because the efficiency gains would not justify the cost.

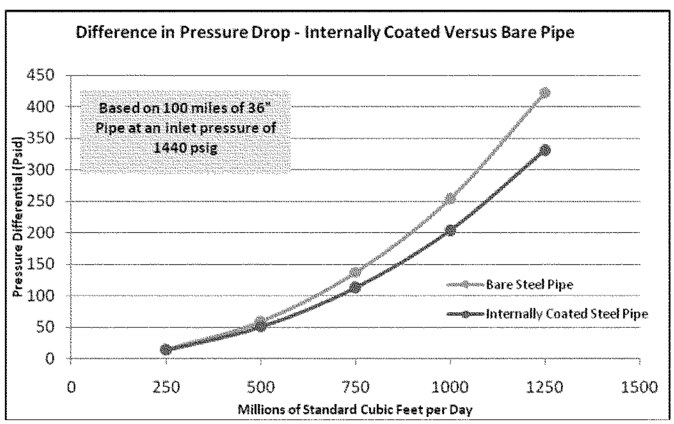

Figure C-1. Pressure Drop on Internally Coated Pipe as a Function of Flow

Appendix D: Compressor Station Location Effect on Efficiency

The location and spacing of compressor stations is another important factor in overall pipeline transportation efficiency. Pipeline companies use advanced simulation programs to determine the best compressor station locations and spacing, considering cost as well as physical space availability, permitting, and reliability needs (for stations at closer locations). The simulation illustrated in Figure D-1 provides an example of the trade off between delivered transportation cost for natural gas vs. pipe mileage that can be used to determine optimal station spacing. The chart shows how the smaller, 30-inch diameter pipelines require shorter spacing between the compressors stations (approximately 60 miles) to achieve the lowest toll because of the increased pressure drop associated with the higher velocities in the smaller diameter pipe. The larger, 36-inch and 42-inch diameter pipelines have a lower pressure drop and therefore can accommodate a wider spacing between stations (80 miles and 100 miles, respectively) to achieve the lowest toll. Still, such decisions cannot be made solely on the basis of reducing cost while optimizing efficiency. Environmental, landowner, and other siting considerations often dictate spacing that is less than optimal from an engineering perspective.

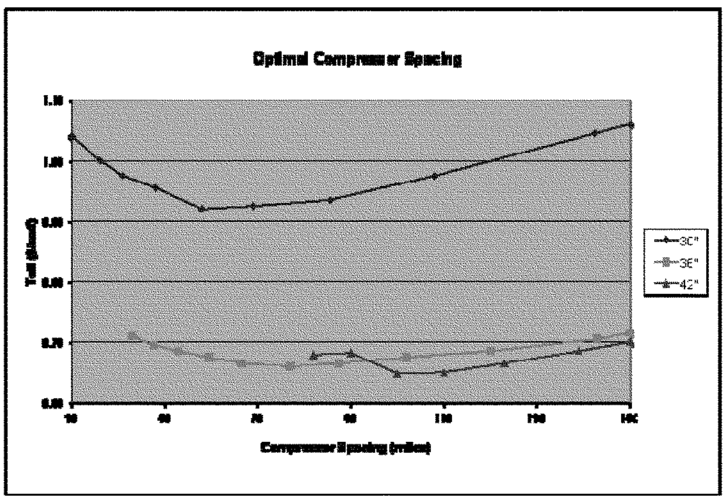

Figure D-1. Optimal Compressor Spacing for Lower Cost per Transported Mcf of Gas per Mile

Appendix E: Recent Research and Development Studies

Study Title	Contractor	Year
Ultrasonic Meter Testing for Storage Applications	SwRI, DOE	1998
Introduction to Smart Pigging in Natural Gas Pipelines	GRI, INGAA, Battelle	2000
Reciprocating Compressor Valve Design: Optimizing valve life and reliability	Derek Woollatt, Dresser-Rand	2002
Turbocharger Center Helps Advance Natural Gas Compression	K.S. Chapman, Pipeline and Gas Journal	Oct 2002
Additional Studies of the Effects of Line Pressure Variations on Ultrasonic Gas Flow Meter Performance	GTI	2003
Increased Flexibility of Turbo-Compressors in Natural Gas Transmission Through Direct Surge Control	SwRI, DOE	2003
Development of an Inspection Platform and a Suite of Sensors for Assessing Corrosion and Mechanical Damage on Unpiggable Transmission Mains	DOE, Northeast Gas Association, Foster-Miller, Inc.	2004
Development of Low-Cost Inferential Natural Gas Energy Flow Rate Prototype Retrofit Module	SwRI, GRI, DOE	2004
Field Testing of Remote Sensor Gas Leak Detection Systems	DOE NETL	2004
Metering Research Facility Program: Additional Studies of Orifice Meter Installation Effects and Expansion Factor	GTI	2004
Metering Research Facility Program: Effects of Turbine Meter Cartridge Change-out on Measurement Uncertainty	GTI	2004
Metering Research Facility ISO Uncertainty Analysis	GTI	2004
Metering Research Facility Program: Pressure Effects and Low Flow Tests on 8-Inch and 6-Inch Ultrasonic Flow Meters	GTI	2004
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Improvement to Pipeline Compressor Engine Reliability through Retrofit Micro-Pilot Ignition Systems – Phase III	Colorado State University, DOE	2005
Metering Research Facility Program: Line Pressure and Low-Flow Effects on Ultrasonic Gas Flow Meter Performance	GTI	2005
Metering Research Facility Program: Natural Gas Sample Collection Handling – Phase V	GTI, SwRI, GRI	2005
Technologies to Enhance the Operation of Existing Natural Gas Compression Infrastructure – Manifold Design for Controlling Engine Air Balance	SwRI, DOE	2005

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Gas Storage Technology Consortium	DOE, Pennsylvania State University, PRCI	2009
Surge Prevention in Centrifugal Compressor Systems	Rainer Kurz and Robert White, Solar Turbines	2007
Evaluate Existing Hydrocarbon Dew Point Measurement Methods & Equipment	PRCI	2008
Alternatives to Gas Expansion Starters	PRCI	2009
Gas Turbine Emissions Compliance	PRCI	2009

The CHAIRMAN. Thank you, Mr. Santa.

Welcome to all of you. Thank you for your comments and what you have provided, not only from a historical perspective but how we might move forward.

Mr. Allen, I am intrigued with what you have outlined for the potential for demonstration projects in rural Alaska. We had an opportunity to describe the situation in many of my communities that are not only not part of a broader grid, they are the very definition of what a true microgrid is.

Mr. Moeller, you mention in your testimony that initially, back in the day, we began as, basically, distributed microgrids. In many cases, I feel in Alaska we are going back to the future. We are letting you know what it is like to be that little independent microgrid.

I would welcome you to come to Alaska, to come out to some of our rural communities, and then give us your insight and guidance. I have an imagineer at Chena Hot Springs that, I think, the two of you could share some very interesting ideas about how we might be able to demonstrate at a very small level in our remote and rural communities, some of the innovations that are out there. So I would welcome you to do that.

I want to ask a question to both you, Mr. Moeller, and to you, Mr. Santa, with regards to comments that are made in your written statements. I will begin with you first, Mr. Santa, because you made a statement and said, "The U.S. natural gas transmission pipeline industry has been funded entirely with private capital."

Mr. SANTA. That is correct.

The CHAIRMAN. I think that is important to highlight, not only to the Committee but to others, to recognize that not all solutions require federal involvement, federal funding.

As we talk about an infrastructure package here, there is no shortage of ideas as to what might go into a broader, economy-wide infrastructure package. What it all comes down to is, how are we going to pay for it?

When we understand that, in fairness, what we have seen with some very significant infrastructure has been a level of investment within the industry that demonstrates that given the right investment climate, these projects can proceed.

Mr. Moeller, you have also suggested, you made a statement that, again, we do not often see here in testimony before Congress. You said, "EEI members are not advocating for additional federal funds for transmission investment." Again, I want to highlight that because, same situation, not all solutions necessarily require federal funding.

So, if I can ask the two of you, in terms of the necessary investment climate for whether those in the natural gas transmission industry to be able to proceed with projects or your members within EEI to be able to proceed to projects, what is it that can and should be done to ensure that we have that necessary investment climate to allow for these particular investments?

Mr. SANTA. I would begin by saying, I think what the investors in pipelines need, and the investors more broadly in energy infrastructure, is certainty and predictability.

In my testimony, I talked about the Natural Gas Act framework and how favorable that has been to encouraging private investment to develop the infrastructure to support this industry.

What we have now though is, and I've noted, there are multiple other permits that are required. That permitting process, I think, can be coordinated more without violating the purposes of many of those statutes that are intended to protect the environment and various resources.

So I would encourage as a complement to whatever may be done on publicly-funded infrastructure in a bill, to also look with an eye toward what can be done to improve permitting for infrastructure.

The CHAIRMAN. So permitting, certainty, coordination.

Mr. Moeller?

Mr. MOELLER. Thank you, Madam Chairman.

The written statement that I have elaborates more on this, but similarly to what Mr. Santa said, siting and permitting reform and certainty and accountability, along with the emphasis on cooperative federalism so that one state doesn't deny the benefits to the citizens and customers of many other states in infrastructure that really is affecting interstate commerce is important.

Specific to the investment climate at FERC, you know, there are some good challenges FERC has based on a period of interesting monetary policy where the formula that was come up with that was rejected by the courts are, frankly, not putting the commensurate return given the risk of transmission investments.

The Commission has to deal with this. We've got a white paper out that's trying to help them on that, and I'll happily give you copies of it.

The CHAIRMAN. Great.

[The white paper information follows:]

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Transmission Investment: Revisiting the Federal Energy Regulatory Commission's Two-Step DCF Methodology for Calculating Allowed Returns on Equity

December 2017

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1: EXECUTIVE SUMMARY

The electric power industry is vital to American jobs and our nation's economy. A recent report, Powering America: The Economic and Workforce Contributions of the U.S. Electric Power Industry,[1] finds that the industry, as a whole, supports more than 7 million American jobs and contributes $880 billion or 5 percent of total gross domestic product ("GDP"). Because virtually every sector of the economy depends on safe, reliable, affordable, and increasingly clean energy, the industry's contribution may be considered the first 5 percent of GDP.

Electric transmission infrastructure is the backbone of the energy grid and is one of the nation's most capital-intensive assets. The energy grid provides a range of benefits to customers, including reliable electricity, congestion relief, robust wholesale market competition, and access to a diverse and changing energy portfolio. New transmission investments also deploy advanced monitoring systems and other technologies designed to ensure a more flexible and resilient energy grid.

Consistent with the goals of the Administration, Congress, and the Federal Energy Regulatory Commission ("Commission" or "FERC"), members of the Edison Electric Institute ("EEI") are committed to investing in the smarter energy infrastructure needed to deliver America's energy future. EEI's member companies invested $20.8 billion in transmission infrastructure in 2016 and expect to invest an additional $90 billion through 2020 to make the transmission system more efficient, more dynamic, and more secure and to continue to provide customers with the affordable, reliable, safe, and increasingly clean energy they need.[2] However, the method by which the Commission establishes allowed shareholder returns on equity ("ROEs")—and, therefore influences private investment in transmission infrastructure—may not adequately support the level of investment needed to maintain and enhance the energy grid.

EEI member companies require shareholder support in the form of capital investment and regulatory support in the form of sound ratemaking policy in order to build, own, and operate the transmission infrastructure that ensures reliable and affordable service to customers. Consistent with long-standing Supreme Court precedent established in *Hope* and *Bluefield*, the Commission is required to set a return on shareholder investment at a level that is "commensurate with returns on investments in other enterprises having corresponding risks,"[3] and that is "sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise capital necessary for the proper discharge of its public duties."[4]

In 2014, the Commission issued Opinion No. 531, with the goal of providing stable, predictable, and adequate returns for transmission investment.[5] That goal, however, has not been achieved despite the Commission's valued efforts. Even with the guidance of Opinion No. 531, ROEs resulting from the current

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[1] M.J. Bradley & Associates (Aug. 2017), http://mjbradley.com/sites/default/files/PoweringAmerica.pdf.

[2] Estimated transmission investments are just that—estimates—and are not guaranteed, as market conditions can and do change. Investor confidence supported by regulatory stability is necessary to ensure that infrastructure needs, including replacement and new infrastructure to meet customer needs, are met.

[3] *FPC v. Hope*, 320 U.S. 591, 603 (1944) ("Hope").

[4] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 693 (1923) ("Bluefield"); *see also FPC v.* Hope, 320 U.S. 591, 603 (1944). ("Commensurate with returns on investments in other enterprises having corresponding risks . . . [and] sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.")

[5] See the transcript of the 1006th Commission Meeting of the Federal Energy Regulatory Commission, Thursday, June 19, 2014. Available at: https://www.ferc.gov/CalendarFiles/20140703074240-transcript.pdf.

Discounted Cash Flow ("DCF") model (which, like all models, has inherent limitations) are producing estimates below other widely accepted alternative ROE estimation models and market indicators, such as state-determined ROEs for lower risk distribution investments, suggesting that these ROE estimates are below levels necessary to support the Commission's stated policy goals and to meet long-standing capital attraction standards. In 2017, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded Opinion No. 531, presenting a very timely opportunity for the Commission to review its model used to calculate the range of values used to set ROEs.

Because transmission infrastructure often is a 50-plus year commitment, investors require adequate and stable returns over the long-term to provide financing for continuous infrastructure re-investment. EEI believes the time is now for the Commission to step-back and to assess whether the inherent limitations (or shortcomings) of the DCF, and the adjustments the Commission has made to the DCF methodology, are leading to outcomes necessary to meet capital attraction standards and policy goals at a time when the transmission system requires expansion and enhancement.

Regardless of the models employed, informed judgment must be applied to determine the applicability of individual model results in the context of the capital market environment. Although the DCF model is theoretically sound, its assumptions are quite limiting and rarely hold outside of the theoretical realm. These assumptions can engender unreliable results, particularly when investor expectations are not consistent with the DCF model's assumption that current market conditions will persist.

Practitioners and academics recognize that financial models simply are tools to be used in the ROE estimation process and that the strict adherence to any single approach, or to the specific results of any single approach, can lead to misleading conclusions. As such, the Commission's recent use of alternative ROE models (such as the CAPM, Risk Premium, and Expected Earning approaches) and market indicators to benchmark and check the reasonableness of the results of the DCF approach is reasonable and should be continued. This position is consistent with the *Hope* and *Bluefield* finding that the method employed is not controlling when determining just and reasonable rate levels.[6] Benchmarking against additional models would balance the fluctuations in the two-step DCF method's results and, ultimately, would increase the stability and reliability of the Commission's approach to ROE estimation.

In addition, this paper recommends the following modifications to temper, but not eliminate, existing shortcomings in the current method of employing the two-step DCF approach:

- Broaden the proxy group by modifying existing screening criteria and expanding the universe of companies eligible for inclusion.
- Consider additional sources of published analyst growth rate estimates when determining the zone of reasonableness.
- Reducing the weight currently given to the GDP growth rate in the application of the two-step DCF method, *i.e.* from 1/3 to 1/5, and incorporating an inflation adjusted long-term GDP estimate such as Morningstar's approach in the *Ibbotson SBBI Valuation Yearbook*; in the alternative, removing GDP from the application of the DCF model altogether.
- Re-examine the thresholds used to determine which DCF results do not pass tests of economic logic, and ensure the thresholds applied appropriately account for current capital market conditions.

EEI is very supportive of the Commission's efforts in Opinion No. 531 to address anomalous market conditions and to revise the DCF methodology to address shortcomings. Despite that effort, however, a rote

[6] *See Hope* at 602.

application of the DCF methodology as conceived in Opinion No. 531 does not produce authorized ROEs adequate to ensure ongoing capital attraction.

EEI offers this white paper to facilitate a holistic review and discussion of the calculation and assessment of transmission investment ROEs, while maintaining the balance between investor and customer interests. We look forward to engaging with all stakeholders to ensure that essential investments in our nation's energy infrastructure can be made today and in the future.

2: INTRODUCTION AND BACKGROUND

The electric transmission network is the backbone of the nation's energy grid. The energy grid connects and enables a diverse and rapidly evolving set of energy resources, ensures reliable service for customers, enables competitive electricity markets, and provides reasonable electricity prices for customers. Transmission accounts for only about 11 percent of an electric customer's total bill, but it is a critical component in delivering reliable, affordable electricity to customers.[7]

As the nation's mix of energy resources continues to evolve and customers demand increased choice over the sources and delivery of their energy, the electric power industry is undergoing significant transformation to enable the flexibility to meet these demands. To this end, electric companies are making significant investments to enhance the transmission system to make it more efficient, more dynamic, and more secure and to continue to provide customers with affordable, reliable, safe, and increasingly clean energy. EEI's member companies are dedicated to planning and enhancing the nation's transmission network to meet customers' changing needs and expectations, investing $20.8 billion in transmission infrastructure in 2016 and an estimated additional $90 billion in transmission infrastructure through 2020.[8]

Congress, the Administration, and the Commission have continuously recognized the numerous benefits of a robust transmission system.[9] For example, the Energy Policy Act of 2005 ("EPAct 2005") set forth several statutory requirements intended to support transmission investment. In 2012, the Commission reaffirmed its pricing policy, which provided incentive rates to ensure electric companies continue developing, constructing, operating, and maintaining the nation's vital transmission infrastructure. In addition, the Commission advanced its strategic goal of supporting transmission development by enabling regional and interregional coordination processes, as well as supporting allocation of costs for the selected transmission solutions that meet customer and system needs. In 2014, the Commission issued Opinion No. 531, discussed in more depth later, with the goal of providing stable, predictable, and adequate returns for transmission investment.[10]

The Commission has significant influence over transmission infrastructure investment through the ROEs it authorizes and the regulatory certainty it provides. This white paper reviews the limitations of the Commission's two-step DCF model and recommends that the Commission take action to ensure that ROEs support and encourage necessary investment in transmission infrastructure.

As this paper demonstrates, the Commission's current application of the two-step DCF model now produces ROEs that are inconsistent with stated Commission policy goals and that do not meet well-established capital attraction standards, strongly indicating that the Commission's current approach is not producing reliable estimates of the just and reasonable rates of return needed to attract investment in transmission infrastructure, particularly in the current capital market environment. The Commission should review the application and

[7] U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017. Reference case. Table 8: Electrical supply, disposition, prices, and emissions. Available at: https://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices

[8] http://www.eei.org/issuesandpolicy/transmission/Pages/default.aspx.

[9] The U.S. Department of Energy's (DOE's) August 2017 Staff Report on Electricity Markets and Reliability acknowledged the need for "major transmission additions to connect the remote generation to the rest of the grid and to load centers." It also recommended that DOE and related federal agencies accelerate and reduce costs for the licensing, relicensing, and permitting of grid infrastructure, including transmission. Available on the DOE website at: https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf

[10] *See Coakley v. Bangor-Hydro Elec. Co.*, Opinion No, 531, 147 FERC ¶ 61,234, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014); *reh'g denied*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015).

results of the two-step DCF method and should make adjustments that would address the limits of the DCF model and that reflect assumptions that are more appropriate given current market conditions.

In particular, this paper highlights the benefits of using alternative models to help estimate and benchmark ROEs. The Commission's recent use of alternative ROE models (such as the CAPM, Risk Premium, and Expected Earning approaches) and market indicators to benchmark and check the reasonableness of the DCF approach in establishing the zone of reasonableness is appropriate and should be continued. Alternative ROE models account for factors and conditions not considered by the DCF model, including measures of capital market risk. Using multiple methods to estimate ROEs is consistent with equity investor practice and helps to ensure ROEs support the Commission's stated policy goals, meet well-established capital attraction standards, and encourage transmission investment. Regardless of the models employed, informed judgment must be applied to determine the applicability of individual model results in the context of the capital market environment.

In addition, the Commission should review assumptions and data inputs that are fundamental to its two-step DCF model. These assumptions are driving the inconsistent ROEs that result from the model. This paper assesses the impacts of certain assumptions and data inputs on the resulting ROEs and suggests that the Commission consider modifying these assumptions. This, too, will help to establish ROEs that are consistent with investor expectations and current market conditions.

In early 2017, the D.C. Circuit remanded Opinion No. 531, in which the Commission adopted the two-step DCF method for electric companies.[11] This presents an opportunity for the Commission to revisit its approach to setting ROEs. Changes to the current DCF model's assumptions, as well as a re-evaluation of the Commission's overall approach to calculating ROEs, are necessary to ensure the consistently just and reasonable returns needed to attract investment at a time when the transmission system is in the process of expansion and enhancement.

2.1 Continued Investment in Transmission Infrastructure Is Critical to the U.S. Economy

The electric power industry is vital to American jobs and our nation's economy. A recent report, Powering America: The Economic and Workforce Contributions of the U.S. Electric Power Industry,[12] finds that the industry as a whole supports more than 7 million American jobs and contributes $880 billion or 5 percent of total GDP. This is the first 5 percent of GDP because virtually every sector of the economy depends on safe, reliable, affordable, and increasingly clean energy.

The electric transmission system is one of the most capital-intensive assets in the country. It provides a range of benefits to customers: reliable electricity service, congestion relief, robust wholesale market competition, and access to diverse energy resources. Because the majority of the U.S. transmission system was built in the 1960s and 1970s, significant replacements and/or upgrades are required now and in coming years to maintain and to improve system performance. Extensive investments also are needed to integrate new renewable and distributed energy resources and to respond to a rapidly changing energy mix. To facilitate this changing energy landscape and to meet customers' changing needs, EEI's member companies continue to introduce innovative transmission technologies, such as fiber optic communications, advanced conductor technology, enhanced power device monitoring, and energy storage devices in transmission projects. At the same time, EEI's members continue to invest in the transmission system to maintain and to improve its resiliency against both cyber and physical threats.

[11] *Emera Maine v. FERC, 854 F.3d 9 (D.C. Cir. 2017).*

[12] M.J. Bradley & Associates (Aug. 2017), http://mjbradley.com/sites/default/files/PoweringAmerica.pdf

2.2 Regulatory Certainty Encourages Private Transmission Investment

Because transmission infrastructure is a long-term commitment, often serving the public for 50 years or more, investors require adequate and stable returns over the life of this infrastructure. The stability and predictability of authorized returns is of paramount importance to investors, who must commit capital to long-lived assets with multi-year development cycles.[13]

Regulatory certainty is needed to obtain and to maintain financing for both new projects and continuous infrastructure re-investments at reasonable cost. Moreover, adequate ROEs serve to maintain the transmission owner's financial integrity, ultimately helping to keep debt rates low to the benefit of customers. The authorized ROE affects not only the cash flows and credit metrics that support the financial strength of the transmission owner, it also provides an indication of the regulatory support—and risk—associated with a given electric company and the jurisdiction in which it operates.[14]

Just and reasonable returns strengthen investors' perception of the regulatory environment and support an electric company's ability to attract capital efficiently throughout various market cycles. Accordingly, it is essential that the Commission's methodology for determining the allowed ROE provide the stable, predictable, and adequate returns needed to attract the investment necessary to expand and to enhance the transmission system.

2.3 ROEs for Transmission Investment Must Be Commensurate With Risks

The U.S. Supreme Court has established the foundation on which a utility's ROE is determined to be just and reasonable, finding that the return should be commensurate with the return available to firms of comparable risk; should compensate investors fairly for capital they have invested; should enable the utility to offer a return adequate to attract new capital on reasonable terms; and should maintain the utility's financial integrity.[15] The Supreme Court recognized that investors have many investment alternatives, even within a given market sector, and, therefore, a company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Investors in transmission assets assume numerous risks and challenges, including long lead times, significant development opposition from affected stakeholders, and extensive state and federal permitting and siting processes. Within the electric power sector, transmission investments differ from other electric company infrastructure investments, including distribution infrastructure, whose projects tend to be smaller in scale, lower in cost, and shorter in duration.[16] DCF estimates for transmission that are below these less risky alternative investments are not commensurate with these risks. This disconnect between DCF results and investment risk discourages investment in transmission and is inconsistent with the U.S. Supreme Court's long-established foundational standards for assessing whether rates are just and reasonable.

[13] Suppliers of equity capital for investor-owned electric companies include individual investors as well as institutional owners, such as pension funds, government retirement funds, mutual funds, insurance companies, and endowments.
[14] The terms "electric company" and "utility," as used in this document, are intended to be consistent with the term "public utility" as it is used in the Federal Power Act [16 U.S.C. § 824(e)].
[15] *See supra* note 3.
[16] Opinion No. 531 at P 149. The Commission found that investing in transmission infrastructure is inherently more risky than distribution infrastructure.

3: THE DCF MODEL: PREMISE, LIMITATIONS, AND COMMISSION APPLICATION

Before discussing the limitations of the DCF model and discussing potential solutions suggested in this paper, it is important to review the theoretical premise of the model and the general issues raised by certain key underpinning assumptions.

3.1 The Theoretical Premise of the DCF Model

The DCF model holds that the price that investors are willing to pay for an asset equals the present value of a future stream of net cash flows discounted at the cost of capital. In the case of a utility stock, the future cash flows received are in the form of dividends (and the appreciation in market price if the stock is sold at the end of a finite holding period).

As the Commission noted, "the underlying premise of the DCF model is that an investment in common stock is worth the present value of the infinite stream of dividends discounted at a market rate commensurate with the investment's risk."[17] The general form of the model is expressed as follows:

Equation [1] - General Form of the DCF Model

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty}$$

	P	=	*The current stock price*
Where:	$D_1 \ldots D_\infty$	=	*Expected future dividends*
	K	=	*The discount rate, or required ROE*

Equation [1], which solves for price from an infinite number of terms, can only be estimated in practice if one is willing to make a variety of assumptions. The simplest version of Equation [1] assumes constant growth in dividends in perpetuity. If we assume that dividends grow at a constant growth g and that g is less than k, Equation [1] reduces to:

Equation [2]

$$P = \frac{D_1}{k-g}$$

If we further assume the market price of a stock reflects its intrinsic value, Equation [2] can be rearranged and used to deduce the required cost of equity. In that case Equation [2] can be simplified and rearranged into the familiar form as shown in Equation [3].

[17] Opinion No. 531 at P 14.

Equation [3]—Constant Growth Model

$$k = \frac{D_0(1+g)}{P} + g$$

Where:	P	=	*The current stock price*
	D_0	=	*The current dividend*
	k	=	*The discount rate, or required ROE*
	g	=	*The expected growth in dividends and stock price*

Equation [3] often is referred to as the "constant growth DCF" model, in which the first term is the expected dividend yield and the second term is the expected capital gains yield (the portion of total return attributable to growth in stock price). This model is intuitively appealing because it makes explicit the two basic ways a firm distributes net income to shareholders. First, a portion of net income is distributed directly through a dividend payment. Second, remaining net income is retained for reinvestment intended to grow earnings and, as a result, increase stock price (capital gains). In this way, there is an inverse relationship between the dividend yield and capital gains yield: the more net income paid out as dividends, the less net income is available to facilitate growth.

3.2 General Limitations of the DCF Model

Although the DCF model is theoretically sound, it is important to recognize that its assumptions are quite restrictive and rarely hold outside of the theoretical realm. To use Equation [3] to estimate a constant required ROE, one must make several strict assumptions, including:

(1) The required ROE is greater than the expected growth rate;
(2) Earnings, book value, dividends, and stock price all grow at the same, constant rate in perpetuity;
(3) The dividend payout ratio remains constant in perpetuity; and
(4) The Price to Earnings ("P/E") ratio remains constant in perpetuity.

DCF model results may be unreliable when investor expectations are not consistent with the DCF model's assumption that current market conditions [*e.g.*, valuations levels (P/E ratios) and dividend payout ratios] will persist in perpetuity.

Evidence on the applicability of the constant growth DCF model is mixed. Academic research has shown that there has been a strong correlation between stock prices and present value calculations when measured over relatively long historical periods, but that the relationship can break down in the short term.[18] Because application of the DCF method to determine the cost of equity assumes that the current stock price reflects the discounted value of expected dividends in perpetuity, the results of the DCF model should be viewed with caution when there is a breakdown in the relationship between stock prices and dividends.

One study focused on back-tests of the constant-growth DCF model concludes that even under "ideal" circumstances,

[18] *See* A. Nasseh, J. Strauss, "Stock prices and the dividend discount model: did their relation break down in the 1990s?" *The Quarterly Review of Economics and Finance* Vol. 44, No. 2, (May 2004), pg. 191–207; *see also,* "The Dividend Discount Model in the Long-Run: A Clinical Study," Foerster, Stephen R; Sapp, Stephen G, *Journal of Applied Finance*; Fall 2005; 15, 2; pg. 55; *see also,* Xiaoquan Jiang and Bon-Soo Lee, "An Empirical Test of the Accounting-Based Residual Income Model and the Traditional Dividend Discount Model," *The Journal of Business*, Vol. 78, No. 4 (July 2005), pg. 1465-1504.

> "… [I]t is difficult to obtain good intrinsic value estimates in models stretching over lengthy periods of time. Shorter horizon models based on five or fewer years show more promise. Any model based on dividend streams of ten years or more, whether as a teaching tool or in practice, should be used with caution, as they are likely to produce low-quality estimates."[19]

Because Equation [3] is derived from a valuation model that assumes a perpetual dividend stream, it is best viewed as an *approximation* of the true required ROE.[20] For example, firms do not pay dividends at a constant dividend yield. Rather, continuous movements in stock prices, coupled with "sticky" dividend policies create continuous changes in dividend yield, contrary to the model's assumptions.

Moreover, the constant growth DCF model assumes that investors are using the net present value analysis in Equation [2] to determine the purchase price they are willing to pay for a stock. Consequently, the DCF model will not produce accurate estimates of the market-required ROE if the market price of a stock diverges from investors' estimates of its intrinsic value (*i.e.*, the calculated net present value of an investment based on its expected risk and return characteristics).

Deviations between market prices and intrinsic valuations can occur when investors take short-term trading positions to hedge risk (*e.g.*, a "flight to safety"), to speculate (*e.g.*, momentum trades), or to increase current income (*i.e.*, a "reach for yield").[21] DCF estimates can also deviate from investors' required return when the growth rates used in the model fail to reflect the investor growth expectations embodied in observable stock prices. Examples of this divergence include investors' speculations over the potential gain from a merger, or investors' valuations reflecting assumptions about future changes to fiscal and monetary policy actions (such as tax policy changes) that have not yet been factored into reported analyst growth rates.

3.3 The Commission's Adoption and Implementation of Its Two-Step DCF Methodology

The two-step DCF approach adopted by the Commission in Opinion No. 531 is a constant growth DCF model that uses a blended growth rate that reflects both short- and long-term growth assumptions.[22] The Commission's two-step DCF method relies on a 6-month average dividend yield[23] and a composite growth rate giving 2/3 weight to short-term analyst earnings growth projections and 1/3 weight to a long-term (GDP) growth rate projection. In Opinion No. 531, the Commission relied on Thomson Reuters' Institutional Brokers' Estimate System ("IBES") five-year analyst earnings growth estimates as the short-term growth rate estimate. To develop the long-term growth rate, the Commission relied on an average of GDP growth projections from IHS Global Insight, the Energy Information Administration ("EIA"), and the Social Security Administration ("SSA").[24] Consistent with prior precedent, the Commission established an ROE

[19] *See* P. McLemore, G. Woodward, and T. Zwirlein, "Back-tests of the Dividend Discount Model Using Time-varying Cost of Equity," *Journal of Applied Finance*, No. 2, 2015, pg. 75-94.
[20] For example, Dr. Roger Morin notes the DCF model does not always provide reliable results in his widely cited text on utility cost of capital. *See* Roger A. Morin, *New Regulatory Finance*, Public Utility Reports, Inc., 2006 at 28, and 431-436.
[21] Some investors may select relatively high dividend yield companies as a "reach for yield" in response to the shortage of investment alternatives that provide adequate yield in today's capital market, rather than investing in stocks based on their long-term return potential.
[22] The form of the constant growth DCF model applied by the Commission reflects the "half growth" approach, where the dividend yield is increased by one half the growth rate.
[23] The monthly dividend yield is based on the latest announced dividend divided by the average of the high and low price for the month.
[24] *See* Opinion No. 531-A at P 39. Also note, the Commission instituted a paper hearing to review the adopted long-term growth estimate and concluded its approach in Opinion No. 531 was reasonable. *See id.* at P 1.

zone of reasonableness using the low and high DCF estimates, excluding low-end results that did not pass tests of economic logic. The Commission relied on the midpoint as the measure of central tendency.[25]

In Opinion No. 531, the Commission relied on DCF model results from a group of comparable-risk companies selected using the following selection criteria:

(1) Is a domestic company considered an electric utility by Value Line Investment Survey ("Value Line");
(2) Has a credit rating no more than one notch above or below the subject utility or utilities, using both Standard & Poor's ("S&P") and Moody's where available;
(3) Pays dividends and has neither made nor announced a dividend cut during the six-month study period;
(4) Has not been party to major merger or acquisition activity during the six-month study period significant enough to distort DCF inputs; and
(5) Has DCF results that pass threshold tests of economic logic.[26]

The Commission's two-step DCF model produces a single growth estimate for each proxy company. Prior to Opinion No. 531, the Commission used a one-step form of the constant growth DCF model. When applying the one-step DCF model, the Commission considered high and low DCF estimates for each proxy company based on high and low dividend estimates and high and low growth estimates.[27] The use of a range of growth rate estimates for each company, rather than a single average growth estimate, generally resulted in a more robust zone of reasonableness.[28]

[25] *See* Opinion No. 531 at PP 9, 118, 122, 142, and 151. The Commission has historically used the midpoint as the measure of central tendency when estimating the cost of equity for a group of electric utilities, and used the median when estimating the cost of equity for a single electric utility; *see id.* at P 26.
[26] *Id.* at PP 92, 114 and 124.
[27] For the dividend component of the model, the Commission considered high and low dividend yield estimates based on the 6-month average of high and low stock prices. For the growth component of the model, the Commission considered analyst growth projections from IBES as well as a sustainable growth estimate. *See id.* at P 25.
[28] In August 2005, Congress enacted the Energy Policy Act of 2005. Seeking to end a two-decades-long period of underinvestment in transmission and, to some extent, in response to the 2003 blackout, Congress dedicated several sections to promote the expansion and modernization of the nation's electricity grid. Congress directed the Commission to establish a program of incentives to invest in electric transmission, recognizing that capital investments in electric transmission infrastructure produce significant benefits for electric customers and society as a whole. Congress directed the Commission to create incentives that, among other things, promote investment in the "enlargement, improvement, maintenance, and operation" of transmission facilities and encourage technologies that enhance the efficiency and operations of existing facilities. In July 2006, the Commission issued a final decision (Order No. 679) establishing its policy on transmission incentives. In 2012, the Commission issued a policy statement clarifying its transmission incentives policy. While not the central focus of this white paper, it is worth noting that when approving ROE incentives, which were encouraged by EPAct 2005, the Commission has traditionally capped the sum of the ROE incentives and the base ROE at the top end of the then-existing zone of reasonableness. In Opinion No. 531, the Commission ruled that in setting a new base ROE, it would revisit whether the combination of previously approved incentive ROEs and the new base ROE exceeded the top end of the newly created zone of reasonableness and, if so, would reduce the total ROE accordingly. *See* Opinion No. 531-B at PP 139-46. Lowering the top end of the zone often causes the total ROE to meet or exceed the cap, creating the additional effect of Opinion No. 531 potentially to limit or cap previously approved ROE incentives.

4: RATES OF RETURN ON EQUITY PRODUCED BY THE COMMISSION'S TWO-STEP DCF ANALYSIS ARE NOT CONSISTENT WITH THOSE PRODUCED BY ALTERNATIVE ROE MODELS AND OTHER MARKET INDICATORS

The Commission uses the two-step DCF analysis to determine an ROE that meets the just and reasonable standard established by the Supreme Court in *Hope and Bluefield*. As noted earlier, under that standard, the return should be commensurate with those available on investments of similar risk and should enable the subject company to attract capital. As also noted earlier, the two-step DCF model is subject to limiting assumptions that may not be valid under all market or company-specific conditions and can produce results that are inconsistent with the "comparable risk" and "financial attraction" standards.

Consequently, it is important the two-step DCF model's results continue to be viewed as indicative, unless confirmed by other analyses. In fact, the Commission did just this in Opinion No. 531 to meet the requirements of *Hope* and *Bluefield* in setting an ROE at a level sufficient to attract investment in interstate electric transmission.[29] The Commission considered the results of additional analyses to benchmark ROE estimates. The Commission ultimately found an authorized ROE higher than the two-step DCF midpoint was appropriate.

Benchmarking against additional ROE analyses is consistent with the *Hope* and *Bluefield* "end result" doctrine, which states that it is the reasonableness of the result, not the method applied, that controls in determining whether a given rate is just and reasonable. Because capital markets change over time, the Commission should not use a formulaic approach or predetermined weighting of any particular model's results, but should continue to use informed judgment in estimating ROEs and to assess model results in the context of alternative ROE measures and other relevant benchmarks. This will help to enable authorized returns that support long-term investment in the transmission system.

The following section compares the midpoint and median electric utility two-step DCF model results to relevant benchmarks, including authorized returns, alternative ROE model results, and other market indicators.[30] This exercise strongly indicates that results of the Commission's current application of the DCF model are not consistent with the results of other models and market indicators, and are not adequate to establish just and reasonable rates.

The two-step DCF results presented below and used for comparative purposes are calculated using the Commission methodology outlined above in section 3.3.[31]

[29] Opinion No. 531 at P 150.
[30] The midpoint is the average of the highest and lowest values. The median is the middle value in a data set arranged in ascending or descending order when there is an odd number of observations, or the average of the two middle-most values when there is an even number of observations.
[31] Consensus analyst growth rate projections are from Bloomberg rather than IBES due to historical data availability. The DCF and alternative ROE models (where applicable) have been applied using the Value Line universe of electric utilities as of April 30, 2017, excluding companies currently involved in major merger activity (Great Plains Energy, NextEra Energy, and Westar Energy). DCF results exclude low-end results that do not pass tests of economic logic, consistent with

4.2 Alternative ROE Models

A variety of well-recognized approaches to asset pricing have been developed in the financial literature, and investors use multiple ROE models in practice. They do so because no single model provides accurate results under all market conditions, and the results of any single model should be viewed in the context of its consistency with alternative ROE methodologies.

Charts 1a and 1b compare semi-annual results of the Commission's two-step DCF model with the results of the alternative ROE estimation methodologies—CAPM, Risk Premium, and Expected Earnings—recently considered by the Commission in electric rate cases. The results below, however, call into question the validity of relying solely on a mechanical application of the two-step DCF model.

As applied here, the Bond Yield Plus Risk Premium model adds an industry-specific premium, adjusted to reflect the current interest rate environment, to the yield on Moody's Baa-rated long-term utility bonds. Under the CAPM approach, a risk premium is specified relative to the yield expectations on Treasury (risk-free) debt. Here, a risk premium reflecting the proxy companies' risk levels relative to the overall market is added to 30-year Treasury yields.

The Expected Earnings analysis calculates the projected returns on book value for the firms in the proxy group using published analyst forecasts provided by Value Line. The model, therefore, provides a direct measure of observable investor expectations for future earned returns on book equity.

Although all three models have their own underlying assumptions and limitations, none is subject to the same limiting assumptions that underpin the two-step DCF model discussed in Section 3. The additional methods, therefore, provide a check on the reasonableness of the two-step DCF model results.[32]

The data in Charts 1a and 1b demonstrate that the recent downward trend in DCF model results is not consistent with the more consistent results from other ROE methods. The application of the ROE models presented here generally are similar to those relied on by the Commission in Opinion No. 531. The methods and assumptions used in the application of the models are discussed in more detail in Section 7.

Commission precedent (*i.e.*, results that are below the 6-month average of Moody's Baa Utility Bond Index yield plus 100 basis points).

[32] The data in charts 1a and 1b also show that any ROE model may produce anomalous results under certain market conditions, such as the relatively high CAPM results in 2007 and 2008. These elevated results were related to relatively elevated Beta coefficients for electric utilities at the time.

Chart 1a: Midpoint Two-Step DCF Model Results vs. Other ROE Estimates

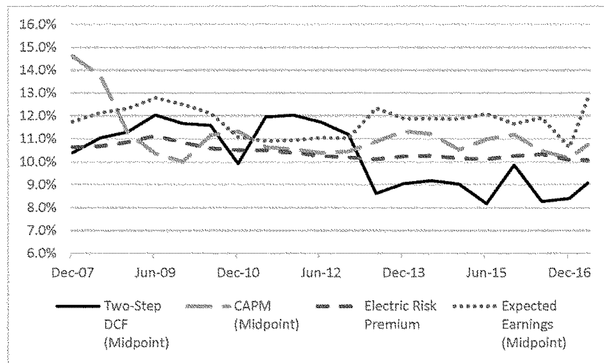
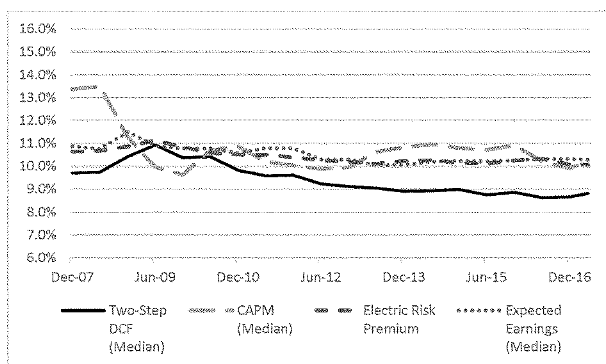


Chart 1b: Median Two-Step DCF Model Results vs. Other ROE Estimates



The CAPM and Risk Premium methods are widely recognized approaches to estimating the cost of equity. Both are based on the basic financial tenet that, because equity investors bear the residual risk associated with ownership, they require a premium over the return they would have earned as a bondholder.[33]

[33] *See, e.g.*, Eugene Brigham and Michael Ehrhardt, *Financial Management: Theory and Practice*, 12th ed. (Mason, OH: South-Western Cengage Learning, 2008), at 346.

4.3 State-Level Authorized ROEs Are Higher Than Recent Two-Step DCF Model Results

Returns available to electric utilities in other jurisdictions are an important consideration for investors.[34] Although the return authorized in any individual case will reflect the particular circumstances of that proceeding, taken together the authorized returns in other jurisdictions represent a comparison point that investors will use to frame their return requirements and arrive at investment decisions. A return that is not competitive on a risk-adjusted basis with those offered for investments in other parts of the electric power industry will diminish the attractiveness of FERC-regulated transmission investments and will push investors to endeavors with more attractive risk-adjusted returns (*e.g.*, distribution facilities).

The Commission's Opinion No. 531 noted that investors providing capital for electric transmission infrastructure face unique challenges that increase their risk relative to state-regulated electric distribution investments. The incremental risks noted by the Commission included "long delays in transmission siting, greater project complexity, environmental impact proceedings, requiring regulatory approval from multiple jurisdictions overseeing permits and rights of way, liquidity risk from financing projects that are large relative to the size of a balance sheet, and shorter investment history."[35] The Commission found that these risk factors increase risk relative to investments made by state-regulated distribution companies. Consequently, in keeping with the Commission's finding in Opinion No. 531, state-authorized ROEs provide a somewhat conservative benchmark.

Two-step DCF results generally are much lower than state-allowed ROEs over the past year. In fact (and as shown in Charts 2a and 2b), the two-step DCF model has produced results below state-regulated ROEs since 2013.

[34] In Opinion No. 531, the Commission used state-commission-authorized ROEs as a lower-bound check on the reasonableness of the two-step DCF model results to prevent Commission-regulated electric transmission companies from being at a competitive disadvantage relative to state-regulated electric utilities when raising capital. *See* Opinion No. 531 at PP 148-150.
[35] *Id.* at P 149.

Chart 2a: Midpoint Two-Step DCF Model Results vs. State-Authorized Electric ROEs[36]

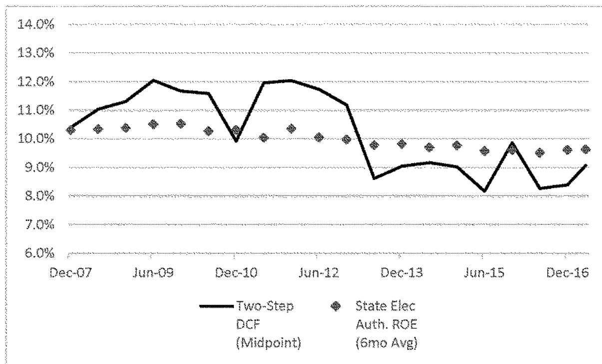
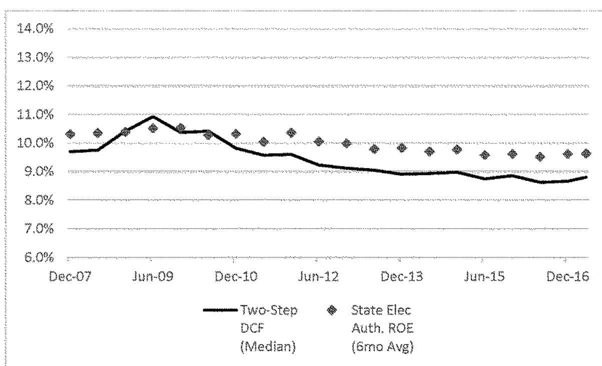


Chart 2b: Median Two-Step DCF Model Results vs. State-Authorized Electric ROEs[37]



4.4 Commission-Authorized Natural Gas Pipeline ROEs Are Another Appropriate Benchmark for Assessing Commission-Authorized ROEs

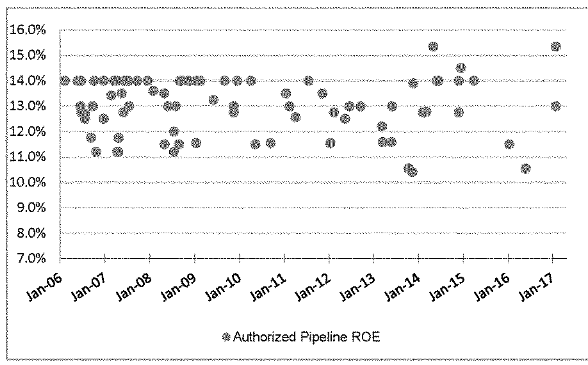
The Commission has used the two-step DCF approach to determine ROEs for natural gas and oil pipelines since the mid-1990s.[38] In *Southern California Edison*, the Commission stated it was not appropriate to

[36] Average of state-authorized ROEs authorized over the previous 6-month period reported by Regulatory Research Associates, calculated semi-annually (e.g., the value for December 2016 reflects the average of all state electric ROEs authorized from 7/1/2016 to 12/31/2016). Excludes limited issue riders and Illinois formula rates.
[37] *Id.*
[38] Opinion No. 531 at P 17.

consider returns in the natural gas industry when evaluating electric utilities because "the electric industry is just beginning a significant new phase of its restructuring."[39] More recently, the Commission found the electric industry and its restructuring have matured.[40] Given the Commission now finds that the same two-step DCF model is appropriate for both industries, the trend in natural gas pipeline ROEs is relevant in assessing the trends in electric transmission ROEs.

Chart 3 suggests that there is no discernible downward trend in the authorized returns for natural gas pipelines.

Chart 3: Commission-Authorized Natural Gas Pipeline ROEs over Time[41]



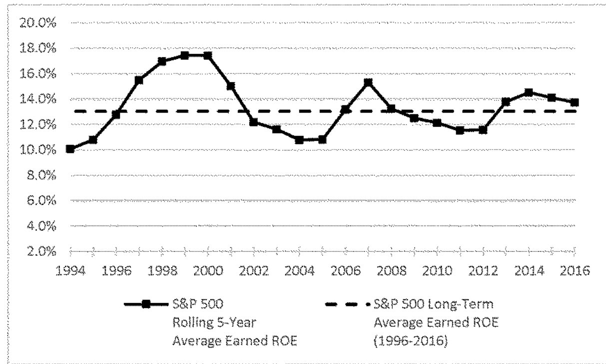
Electric and natural gas transmission operations both are federally regulated, capital-intensive infrastructure investments. To the extent the Commission's authorized ROEs for natural gas pipelines have not declined, the implied decline in required ROE for electric utilities (based on DCF results) warrants an investigation as to why the DCF model now produces lower results for electric utilities.

4.5 Earned ROEs for the Overall Market Have Not Declined; Therefore, a Declining Trend in ROEs for Electric Utilities Should Be Questioned

Another check on the reasonableness of the downward trend in required ROE for electric utilities implied by the two-step DCF model is the trend in the actual earned return on common equity for the overall equity market (as measured by the S&P 500 index; *see* Chart 4). As Chart 4 indicates, the weighted average earned return on common equity for companies in the S&P 500 index has fluctuated around its long-term average of approximately 13.00 percent, with the most recent five-year average reflecting a slightly higher return of 13.74 percent.[42]

[39] *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 at 61,261 (2000).
[40] *See* Opinion No. 531 at PP 35-36.
[41] Includes LNG. FERC-authorized ROEs based on general review of Commission orders available on: https://elibrary.ferc.gov/idmws/search/fercgensearch.asp.
[42] That is, the five-year average as of 2016. Source: Bloomberg Professional. Note, electric company risk as measured by the median Value Line Beta coefficient has been fairly stable since at least 2009, fluctuating between 0.70 and 0.75.

Chart 4: Moving 5-year Average Earned Return on Common Equity for S&P 500



To the extent the overall market's most recent five-year-average earned ROE has been above its long-term average, the downward trend in the required ROE for electric utilities implied by the two-step DCF model is a divergence from general trends in the competitive capital market.[43]

4.6 Conclusion

For more than 30 years, the Commission has relied on some form of the DCF model as its principal method of estimating the cost of equity for electric utilities.[44] However, in recent years, this approach is not producing results that achieve the stated FERC policy goals or meet long-standing capital attraction standards.[45] Other widely accepted models suggest required shareholder returns are higher.

Sole reliance on the two-step DCF method can produce volatile cost of equity estimates because inputs and, therefore, results can and do change significantly from day to day. Benchmarking against other models would help to establish more stable ROE estimates. As noted in *Hope*, the Commission is not bound to the use of any single formula or set of formulae in determining rates.[46] Section 6 of this paper discusses alternative ROE models that the Commission should consider as benchmarks, along with the two-step DCF methodology, when determining an electric company's authorized ROE.

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[43] The earned return on common equity is a backward-looking accounting measure, whereas authorized ROEs are set prospectively based on market data. Nonetheless, the earned ROE provides an indication of whether there has been an overall downward trend on the return earned on equity investments for the market generally.
[44] *See, e.g.*, Opinion No. 531 at P 14, which notes the Commission has relied on the DCF model to provide an estimate of the investors' required rate of return for more than 30 years.
[45] In addition to the concerns expressed herein about the Commission's methodology for calculating ROE, the Commission has moved away from the broader goals of stability and predictability noted above by automatically setting any and all complaints for hearing and settlement, including those that "pancake" proceedings, creating an atmosphere of endless litigation and uncertainty. Despite the issuance of Opinion No. 531, transmission owners in New England and, by extension, the transmission-owning industry have endured six years of litigation without concrete ROEs. No clarity on the issue is in sight. Though not the focus of this white paper, the lack of certainty—which is a risk—caused by pancaked complaints and years of litigation has caught the eye of investor analysts and the financial community. The Commission should revisit its policy of allowing pancaked complaints as inconsistent with the FPA and the goals of certainty and efficiency.
[46] 320 U.S. at 602.

Results of alternative ROE models, as well as additional observable benchmarks (*e.g.*, the returns allowed to state-regulated utilities and the returns earned by public companies in the overall market), suggest the Commission's two-step DCF methodology may not always provide reasonable estimates of the cost of equity for electric transmission assets. As discussed in the next section, addressing specific issues with the application of the two-step DCF model may improve the likelihood the model will produce reliable estimates of market-required returns. The Commission has the flexibility to address these issues.

5: THE COMMISSION CAN ADJUST ASSUMPTIONS AND DATA INPUTS USED IN THE DCF METHODOLOGY TO HELP ENSURE THAT AUTHORIZED RETURNS ARE JUST AND REASONABLE

The following section discusses issues with the assumptions and data inputs used in the Commission's current application of the two-step DCF model and provides recommendations for potential modifications.

5.1 Proxy Group Selection for the Electric Power Industry

The cost of equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. Because the cost of equity is a market-based concept, a group of publicly traded, risk-comparable companies typically is selected to serve as "proxies" in the application of ROE analyses. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

As noted, the Commission historically has relied on DCF analyses applied to proxy groups selected from the universe of companies considered electric utilities by Value Line. Selecting proxy companies that operate within the same general industry (*i.e.*, companies with regulated electric utility operations) is a practical and helpful approach to assembling an appropriately risk-comparable proxy group. It may, however, prove less reliable when electric companies are insufficient in number to provide a robust sample size, and there are no publicly traded, pure-play electric transmission companies to include in the proxy group.

The lack of a large, representative comparison group has become an increasing concern in recent years. Notably, the Value Line universe of electric utilities has declined in number over time, due to industry merger and acquisition activity. In early 2012, there were 52 companies in Value Line's universe of electric utilities across all credit ratings; by April 2017, the universe included 40 companies—a decline of nearly 25 percent.

Table 1: Mergers & Acquisitions in the Value Line Electric Utility Universe

	2012	2013	2014	2015	2016	2017
Electric Utility Count (beginning of year)	52	48	47	46	46	40
Removed Companies (Tickers; removed due to mergers and acquisitions)	• CV • CEG • PGN	• CHG • NVE	• UNS	• TEG • UIL	• CNL • ITC • POM • TE	• EDE

Looking back further, the change has been even more extreme. The current universe is less than half the size it was in the early 1990s when EEI reported tracking 100 investor-owned electric companies.[47]

Not only has the number of publicly-traded electric companies declined as target companies are merged into acquirers, the acquiring companies themselves often are electric utilities. Because one of the Commission's screening criteria excludes companies that are party to a merger or acquisition during the six-month study period significant enough to distort DCF inputs, the increase in utility merger activity further reduces the universe of potential proxy companies. The ultimate effect is a smaller and possibly less robust proxy group to which the DCF model can be applied.

Acquisitions also may have a significant effect on the zone of reasonableness established by the two-step DCF approach. For example, the DCF result for UIL Holdings Corporation set the top of the zone of reasonableness established in Opinion No. 531, but the company was acquired by Iberdrola S.A. in February 2015. Likewise, TECO Energy, Inc.'s DCF result set the high end of the zone of reasonableness in Opinion No. 551; that company was acquired by Emera Inc. in September 2015.[48,49] Once those companies were acquired and no longer eligible proxies, the top of the range of reasonableness was reduced.

5.1.1 Potential Proxy Group Modification 1— Loosen Credit Rating Screen

Among the Commission's screening criteria is the requirement that proxy companies be rated within one credit rating "notch" (above or below) of the subject company (or companies) by both S&P's and Moody's ratings services. That requirement is overly restrictive, however, because the critical distinction from the perspective of equity holders is not based on credit ratings notches. Instead, it is based on whether a given company is rated above or below investment grade. Relaxing the credit rating threshold would increase the number of potential proxy companies while maintaining a sufficient degree of comparability, particularly for rate cases that involve a single electric company.

The proxy companies used to estimate the cost of equity for a company, or a group of companies, should have comparable equity risk. Credit ratings, however, are provided for the benefit of debt (bond) investors—they are not precise measures of equity (stock) risk. A credit rating is an evaluation of a borrower's ability to meet its financial obligations (debt payments) in a timely manner. Because debt and equity are fundamentally different securities with different risk and return profiles, different lives, and different investors, there is not a direct relationship between credit ratings and the cost of equity.[50]

Because credit ratings can provide general information regarding risk and access to debt capital, they can provide a relevant data point. Credit ratings, however, are not direct measures of equity risk and the salient issue for selecting proxy companies is whether or not a company is below investment grade. Being below investment grade can meaningfully impair access to capital at reasonable terms and cost, and may preclude some institutional investors from purchasing the company's stock. Loosening the credit rating screening criteria to include all investment grade utilities would expand the pool of utilities available for inclusion in

[47] *See* Edison Electric Institute, *1992 Financial Review—Annual Report of the Investor-Owned Electric Utility Industry* (1993), at 43. The latest EEI index of investor-owned electric utilities included 44 companies; *see*, Edison Electric Institute, *2016 Financial Review—Annual Report of the U.S. Investor-Owned Electric Utility Industry* (2017), at 101.
[48] Opinion No. 531 at P 125 and Appendix.
[49] *Ass'n of Businesses Advocating Tariff Equity, et al. v. MISO*, Opinion No. 551, 156 FERC ¶ 61,234 at PP 20 and 65 (2016).
[50] For example, debt investors have a contractual, priority claim on cash flows not available to equity investors, and, as such, equity investors bear the residual risk of ownership. Further, because the life of debt is finite, debt investors' exposure to business and financial risk likewise is finite. Equity, on the other hand is perpetual and as such, equity investors are exposed to residual risk in perpetuity.

the proxy group. At a minimum, the Commission should include within the proxy group utilities within one notch of the subject utility based on either S&P or Moody's ratings, rather than both.

Charts 5a and 5b show that as of April 30, 2017, the majority of electric utilities fall into Standard & Poor's BBB- to A ratings range and Moody's equivalent Baa3 to A3 ratings range.[51]

Chart 5a: Value Line Electric Utilities—S&P's Credit Ratings

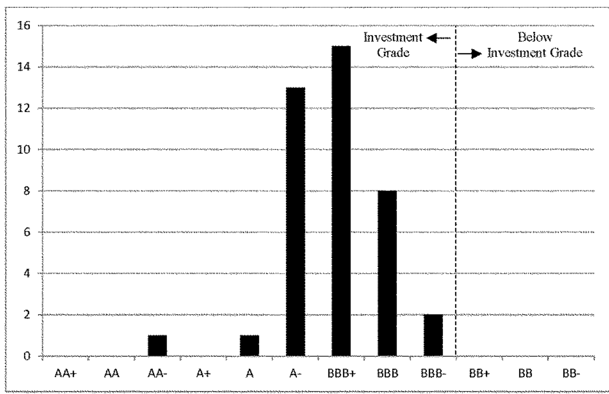
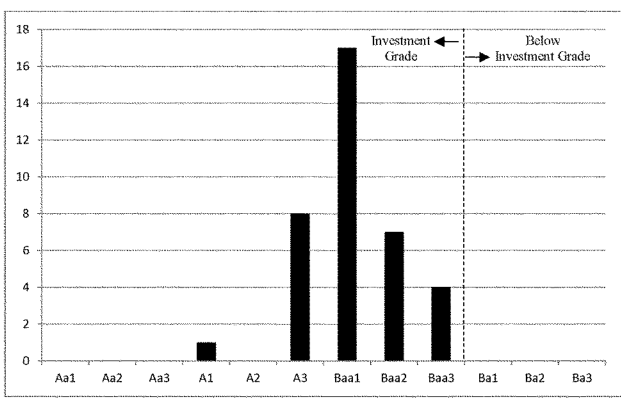


Chart 5b: Value Line Electric Utilities—Moody's Credit Ratings



[51] Source: SNL Financial.

Table 2 provides two-step DCF results as of April 30, 2017, for a set of potential proxy groups selected using S&P credit rating ranges. If there was a direct relationship between credit ratings and the cost of equity, we would expect to see the lowest credit ratings associated with the highest cost of equity, reflecting the assumption that changes in ratings notches directly reflect changes in equity risk. However, the relationship is not demonstrated in the two-step DCF model results. Rather, the lowest DCF result (8.07 percent) is associated with the lowest credit rating (BBB-); there is no meaningful difference in DCF results among the remaining ratings notches. This demonstrates that the present credit rating criteria do not serve as an appropriate basis to fine-tune ROE estimates based on relative risk.

Table 2: Median Two-Step DCF Results Using S&P Credit Rating Screen Scenarios[52]

Company Rating:	No Screen	A-	BBB+	BBB	BBB-
Proxy Rating Range (-/+ one notch)	All Investment Grade	BBB+/A	BBB/A-	BBB-/BBB+	BB+/BBB
Median DCF	8.81%	8.88%	8.86%	8.79%	8.07%
Proxy Group Count	36	27	33	23	10

5.1.2 Potential Proxy Group Modification 2—Consider a Separate DCF Analysis Using Companies from Other Industries as a Secondary Benchmark

Because there are no publicly traded, pure-play transmission companies, the proxy group already implicitly reflects business segments beyond electric transmission operations. The *Hope* and *Bluefield* comparability standard does not limit the selection of proxy companies to those operating in the same industry. Cost of equity estimates from other rate-regulated industries, or non-utility companies with similar overall equity investment risk levels, may provide a useful corroborating method to determine returns that will enable electric transmission assets to attract capital efficiently and effectively in an open and competitive market.

Cost of equity estimates for oil and natural gas pipelines, for example, would provide information regarding the return expected from the wider breadth of investor choices truly available when investing in the utility industry. As noted above, the Commission's decision to begin using the two-step DCF model for electric utilities was premised, in part, on the conclusion that electric utilities have reached a more mature stage of development and now can be valued in a similar manner as oil and natural gas pipelines. Pipeline companies to consider for inclusion in future benchmark analyses when estimating ROE for electric transmission companies may include Kinder Morgan, Boardwalk Pipeline Partners, EnLink Midstream Partners, Energy Transfer Partners, Spectra Energy Partners, TC Pipelines, and Williams Partners LP.[53]

In addition, because utilities must compete for capital with the universe of investment opportunities available in the market place, non-regulated firms with comparable total risk may provide a useful proxy for determining the cost of equity for electric transmission investments. A risk-comparable non-utility proxy group could be identified using selection criteria that screen based on risk characteristics including, but not necessarily limited

[52] Note: there were no Value Line electric utilities with an S&P credit rating of BB+. Although there is no utility rated below investment grade at present, such companies may have a different risk profile and, therefore, should be excluded.
[53] Pipeline companies listed are covered by Value Line and report greater than 50 percent of operating income from oil and natural gas transmission operations. We recognize the Commission opened a notice of inquiry in Docket No. PL17-1-000 to look at the use of master limited partnerships ("MLPs") in proxy groups for MLP rate proceedings, with regard to the issue of income tax recovery.

to, (1) credit rating (*i.e.*, requiring investment grade ratings); (2) Beta coefficient; (3) Value Line Safety Rating; (4) Value Line Financial Strength Rating; (5) dividend yield; (6) market capitalization; and (7) country of domicile.

5.2 Selection of Analyst Growth Rate Estimates

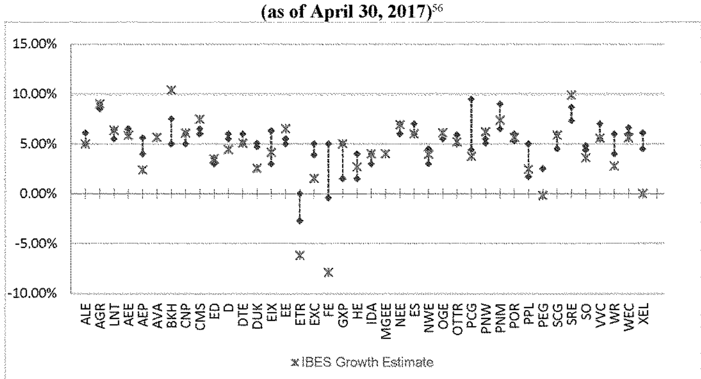
As noted above, the DCF model requires an estimate of investors' expectations regarding earnings growth. As also discussed earlier, the Commission's two-step DCF approach assigns analysts' growth estimates two-thirds weight in the final composite growth estimate. Although the Commission has noted it does not require the use of analyst growth rate estimates from IBES,[54] in practice the Commission has relied on IBES data. The sole reliance on near-term earnings growth projections reported by a single source (*i.e.*, the Thomson Reuters' IBES database) unnecessarily limits the breadth of market data used in the model.

Investors have access to many credible sources of growth rate estimates, and different investors will have different growth assumptions. Institutional and other large investors often employ analysts (sometimes referred to as "buy side" analysts) who may develop their own growth estimates rather than relying entirely on reported consensus estimates.

Consequently, a single data provider may not adequately capture the growth rate expectations associated with the marginal investor driving stock valuations at any given time. In the current market environment, for example, relatively high industry valuations may reflect above-average earnings growth rate assumptions by some investors.[55] Reported growth rate projections from a single source, whether IBES or any other provider, may not capture those expectations. While they presumably represent averages from multiple sources, consensus growth estimates from different data providers may vary widely for a given company, depending on the identity, number, and reporting frequency of the underlying contributors. To illustrate, Chart 6 compares IBES' reported EPS growth rate projections to the range of growth rates reported by other widely used data sources including Bloomberg, Zacks, and Value Line.

[54] *See* Opinion No. 531 at P 90. The Commission did not mandate the use of IBES growth rates, but did say they should be from a consistent source. "[W]hile we reaffirm that there may be more than one valid source of growth rate estimates, in order to ensure that growth rate estimates are internally consistent in an ROE analysis we find it inappropriate to use estimates from different sources for different proxy group companies."
[55] Current electric utility P/E ratios are above their long-term historical average levels and are elevated relative to the overall market.

Chart 6: EPS Growth Projections—IBES vs. Zacks, Value Line, and Bloomberg (as of April 30, 2017)[56]



As Chart 6 points out, published growth rate projections vary for the same company, sometimes significantly so. Because restricting growth rate estimates to a single source, such as IBES, fails to account for the range of growth rate assumptions likely used by investors, that practice also may produce ranges of results that do not capture investors' return requirements fully.

5.2.1 Potential Analyst Growth Rate Modification—Use Growth Rate Projections from Multiple Providers

Because the DCF model is used to estimate investors' required ROE, it is important that the inputs to the model reflect the assumptions made by investors. Investors use data from a variety of data sources to develop their return expectations, and a wide range of growth estimates may be reflected in stock prices. Relying on growth rate data from multiple credible sources and calculating high and low two-step DCF estimates using the highest and lowest growth rate estimates to set the zone of reasonableness, regardless of whether those estimates came from the same investor service company, would provide a range of ROE estimates that reflects the range of assumptions relied on by individual market participants.[57] Including additional sources of published growth rate projection data would be consistent with the Efficient Market Hypothesis, which suggests market prices reflect all publicly available information. Considering a range of high and low results would be similar to the approach previously used by the Commission when it relied on the one-step DCF model. Doing so also would help to address concerns that parties themselves have raised regarding IBES estimates.

[56] IBES growth rate estimates reported by Yahoo!Finance. Note, Value Line growth rates are reported quarterly.
[57] To be clear, we do not recommend the Commission average the results, as this would not reflect the full range of investor expectations. Rather, the DCF should be performed for each company using investor service data separately. The lowest DCF result would set the bottom of the range (subject to a low-end threshold screen), and the highest DCF result would set the high end of the range.

5.3 Long-Term Growth Rate Estimate and Its Weighting

The blended growth rate used in the Commission's two-step DCF methodology assigns one-third weight to long-term projections of GDP growth, which gives the GDP growth estimate a significant influence on the end result. There is, however, a lack of evidence to indicate that investors' growth expectations for electric utilities have begun to converge with the economy.

As the Commission has noted, long-term projections are "inherently more difficult to make, and thus less reliable."[58] Even if investors have started to assume electric utilities' growth will begin to converge to GDP growth in the foreseeable future, it is not clear that the economic forecasts relied on by the Commission (from SSA, EIA and Global Insights) accurately reflect what investors expect in perpetuity.

The long-term GDP projections from sources such as those used by the Commission generally represent growth assumptions over a fixed period of time and reflect assumptions regarding a range of uncertain future conditions such as tax and trade policies, central bank monetary policies, worker productivity growth, workforce participation, and many other factors.[59] Rather than assume current policies and economic conditions will remain in place forever, a reasonable approach is to rely on historical average nominal growth observed over an approximately 90-year period—including a number of economic cycles, monetary policy conditions, and fiscal policy conditions—as a benchmark for expected long-term future growth. As a point of reference, the 4.39 percent GDP growth projection used by the Commission in Opinion No. 531 is 174 basis points below the long-term historical nominal GDP growth of 6.13 percent reported by the U.S. Bureau of Economic Analysis.[60]

Table 3 provides another perspective, comparing GDP projections consistent with the Commission's prescribed approach (averaging together SSA, EIA, and Global Insights estimates) to the long-term growth rate implied by state-level authorized ROEs and contemporaneous electric utility dividend yields.[61]

[58] Opinion No. 531 at P 21, citing Opinion 414-A.
[59] For example, EIA's "reference case" forecasts assume factors, such as current laws and regulations, are unchanged throughout the forecast period (*see* Annual Energy Outlook 2017 with projections to 2050, at 6.)
[60] *See* Bureau of Economic Analysis, "Current-Dollar and 'Real' Gross Domestic Product," May 26, 2017 release. Nominal GDP grew from $104.60 billion in 1929 to $18.57 trillion in 2016, reflecting a geometric average growth rate of 6.13 percent annually.
[61] Note, this analysis is representative only. The specific dividend yields of the companies used as proxies in the individual rate cases will vary.

Table 3: Growth Rates Implied by Recent State-Authorized ROEs[62]

Year	Average of Recent State-Allowed ROEs	Average Electric Utility Dividend Yield	Implied Growth Rate
2017 YTD	9.64%	3.07%	6.47%
2016	9.60%	3.17%	6.33%
2015	9.60%	3.55%	5.94%
2014	9.75%	3.51%	6.13%
2013	9.81%	3.83%	5.87%
2012	10.01%	3.91%	5.98%
2011	10.19%	4.17%	5.89%
2010	10.29%	4.46%	5.71%
2009	10.52%	4.69%	5.70%
2008	10.37%	3.64%	6.61%
2007	10.31%	2.90%	7.30%
Average:	10.01%	3.72%	6.18%

The implied growth rates shown in Table 3 are generally consistent with the assumption that over time, GDP growth reverts to its long-term mean (*i.e.*, the 6.13 percent long-term growth rate noted above). Over the same 2007 to 2017 period, long-term growth rates calculated using the approach adopted by the Commission would have ranged from approximately 4.30 percent to 4.70 percent, averaging 4.40 percent.[63]

Finally, electric utility P/E ratios currently are elevated relative to both their historical average level and relative to the broad market as measured by the S&P 500. If valuations are driven by investors' expectations that electric utility growth rates are beginning to moderate and converge toward a relatively lower long-term rate of U.S. economic growth, it is not clear why their P/E ratios would be higher now than historically observed. To the extent current stock price valuations are driven by factors other than long-term GDP assumptions, the rationale for using long-term GDP projections in the two-step DCF model is undermined.

5.3.1 Potential Long-Term Growth Modification 1—Lower Weight Given to GDP Growth, or Discontinue Use

The Commission's use of GDP growth in the two-step DCF model does not adequately reflect the continuing growth opportunities for electric companies.[64] The industry is undergoing significant transformation, and public utilities are making significant investments to make the energy grid smarter, cleaner, stronger, more dynamic, and more secure and to integrate a rapidly changing mix of energy resources.[65] Investors may see

[62] Source: SNL Financial. Dividend yield based on the market capitalization weighted SNL electric utility index. Consistent with the half-growth form of the constant growth DCF model used by the Commission, the implied growth rate is calculated as (ROE - Yield / (.5 x Yield +1).
[63] Based on a review of long-term growth rates referenced in the Commission's electric, oil, and natural gas transmission rate case orders.
[64] This paper does not explore the relationship between other Commission jurisdictional entities and GDP growth.
[65] *See, e.g., From growth to modernization: The changing capital focus of the U.S. utility sector*, Deloitte, June 2016.

potential growth paths for utilities that differ from GDP indicators, and as such, they may give little or no weight to the long-term GDP growth rate. Therefore, it would be reasonable to reduce the weight given to GDP growth in the Commission's blended growth rate calculation (*e.g.* from one-third to one-fifth) or to remove GDP growth from the application of the DCF analysis altogether (while still considering other adjustments discussed in this paper).

Moreover, if investors believe that the public utility industry is in the mature phase of its lifecycle, it should already be reflected in the reported growth rate expectations for public utilities. Accordingly, there is no need to adjust investors' earnings growth rate expectations toward macroeconomic estimates of long-term GDP growth.

To the degree there is inherent uncertainty associated with the long-term GDP growth estimate, caution should be used when assigning the weight given to GDP forecasts.

5.3.2 Potential Long-Term Growth Modification 2—Adopt a Revised GDP Growth Calculation

The economic forecasts of nominal GDP growth relied on by the Commission may not be congruent with the long-term growth expectations reflected in utility stock market prices. Because the DCF methodology places investors' expectations of future growth at the center of its assumptions, utilizing an unrepresentative growth assumption would lead to distorted ROE estimates. An alternate approach is to assume that, over time, real GDP growth is mean-reverting. Morningstar's Ibbotson SBBI Valuation Yearbook, for example, describes a long-term GDP estimate for use as a long-term DCF growth rate that adds a market-based measure of inflation to the historical average real GDP growth rate. Morningstar's approach assumes real GDP will converge toward its historical average growth rate, while forward-looking inflation is estimated using the spread between nominal and inflation-protected U.S. Treasury securities.[66] As of April 2017, Morningstar's method produces a long-term nominal GDP estimate of 5.27 percent, based on a historical real GDP growth of 3.22 percent and a projected long-term inflation rate of 2.05 percent.[67]

5.4 Low-end Threshold Test

As noted in Opinion No. 531, the Commission precedent has been to exclude low-end results "whose cost of equity estimates fail tests of reasonableness and economic logic."[68] To exclude ROE estimates that "are sufficiently low that an investor would consider the stock to yield essentially the same return as debt," the Commission historically has applied a low-end threshold of approximately 100 basis points above utility bond yields.[69] The Commission has noted the low-end test is a "flexible test."[70]

The Commission's general approach of using the cost of debt to establish a minimum threshold for estimates of the required ROE is logical, as equity investors require a risk premium above the cost of debt to compensate them for the residual risks associated with owning common stock. Debt holders are entitled to contractually obligated payments, have protections provided by debt covenants and other restrictions, and have priority claim on assets in the event of insolvency. Equity holders are not entitled to the same protections and, therefore, are exposed to incremental (sometimes referred to as "residual") business and financial risks.

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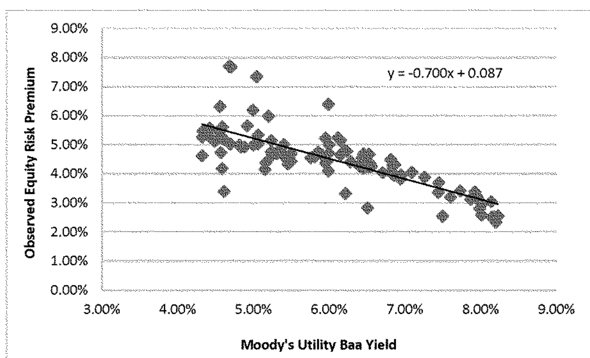
[66] *See Ibbotson SBBI 2013 Valuation Yearbook*, Morningstar, Inc., at 50-52.
[67] Geometric average U.S. GDP growth from 1929-2016 as reported by the U.S. Bureau of Economic Analysis; projected inflation calculated as the 30-day average difference between nominal and inflation-protected 30-year Treasury yields as of April 28, 2017.
[68] Opinion No. 531 at P 119.
[69] *Id.* at P 122.
[70] *Id.*

The required equity risk premium, however, changes over time. Prior research has shown, for example, the equity risk premium to be inversely related to the change in the level of interest rates.[71] That is, as interest rates decline, the required risk premium increases (and, as interest rates increase, the required risk premium declines). As shown in Chart 7a, there is an inverse relationship between interest rates and the equity risk premium implied by Commission-authorized ROEs; since 2007, the equity risk premium increased approximately 70 basis points for every 100-basis point decline in Baa utility bond yields.[72]

Chart 7a: Inverse Relationship Between Equity Risk Premium and Baa Utility Bonds Yields—Commission-Authorized ROEs



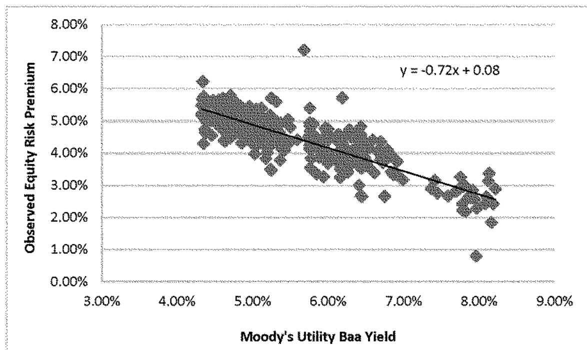
Similarly, the equity risk premium implied by state-level authorized ROEs increased by approximately 72 basis points for every 100 basis point decline in Baa utility bond yields.[73]

[71] *See, e.g.*, Robert S. Harris and Felicia C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Summer 1992, at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry," *Financial Management*, Autumn 1995, at 89-95.

[72] 6-month average Baa-rated utility bond yields. Commission-authorized base ROEs; data from general review of Commission orders available at: https://elibrary.ferc.gov/idmws/search/fercgensearch.asp.

[73] 6-month average Baa-rated utility bond yields. Authorized ROE data from Regulatory Research Associates.

Chart 7b: Inverse Relationship Between Equity Risk Premium and Baa Utility Bonds Yields—State-Authorized ROEs



The Commission has used a risk premium generally close to 100 basis points since at least 2006, when it found results 97 to 126 basis points above the average yield for public utility debt were too low to be credible.[74] Given the relatively large changes in the capital market environment over that period, including unprecedented changes in monetary policy, a premium near 100 basis points no longer provides a reasonable low-end threshold check and should be increased. The cost of equity is a forward-looking concept, and the Commission's low-end tests should also be forward-looking.

5.4.1 Potential Low-End Test Modification 1—Use a Dynamic Threshold That Reflects Changes in Interest Rates

There is a well-established inverse relationship between interest rates and the equity risk premium. Recognizing and accounting for that relationship would improve the low-end test. Assuming the equity risk premium increases approximately 70 basis points for every 100-basis point decline in utility bond yields (*see* Chart 7a), the nearly 200 basis point decline in the six-month average Moody's Baa utility bond yield since 2006 suggests the risk premium should currently be approximately 240 basis points.

5.4.2 Potential Low-End Test Modification 2—Consider Using Published Bond Yield Forecasts

In response to extraordinary financial market dislocation in 2008, the Federal Reserve: (1) lowered the Federal Funds rate from 5.25 percent in September 2007 to near zero by December 2008; and (2) purchased approximately $4 trillion of U.S. agency debt and mortgage-backed securities with the specific intent of putting "downward pressure" on long-term interest rates.[75] As of the end of 2016, the Federal Reserve held approximately 36 percent of the supply of U.S. government Treasury securities with maturities over 10 years.[76] In December 2015, the Federal Reserve raised the Federal Funds rate for the first time in nine years

[74] *See Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 135 (2006), *order on reh'g*, Opinion No. 486-A, 123 FERC ¶ 61,056 (2008), *order on reh'g*, Opinion No. 486-B, 126 FERC ¶ 61,034 (2009).
[75] *See* http://www.federalreserve.gov/monetarypolicy/openmarket.htm. *See also*: Federal Reserve Board Schedule H.4.1.
[76] Federal Reserve Bank of New York, *Domestic Open Market Operations During 2016*, April 2017 at 25.

and began the process of rate "normalization." More recently the Federal Reserve has begun addressing the "unwinding" of the balance sheet, although the ultimate path and timing of that process remain uncertain. [77]

As the Federal Reserve continues to move forward with interest rate normalization, investors expect rates to continue to increase from their historically low levels. As of June 2017, consensus projections provided by *Blue Chip Financial Forecasts* show corporate Baa debt yields are expected to increase from 4.7 percent in Q2 2017 to 5.6 percent in Q3 2018.[78] Corporate Baa debt yields are expected to further increase to 6.3 percent by 2020.[79] Applying the Commission's approximately 100 basis point premium to published consensus bond yield forecasts would address investors' expectations for changing capital market conditions. Using *Blue Chip Financial Forecasts*' projected Baa debt yields, the low-end threshold would currently be in the range of 6.6 percent to 7.3 percent.

[77] Minutes of the Federal Open Market Committee, March 14-15, 2017. The FOMC minutes indicate committee participants anticipate a change in reinvestment policy later this year, which would be a significant first step in unwinding the additions made to the Federal Reserve's balance sheet as part of QE.
[78] *See* Blue Chip Financial Forecast, Vol. 36 No. 6, June 1, 2017, at 2.
[79] *See id* at 14.

6: THE COMMISSION SHOULD ALSO CONSIDER BENCHMARKING AGAINST ALTERNATIVE MODELS TO HELP ENSURE THAT AUTHORIZED RETURNS ARE JUST AND REASONABLE

The following section provides a high-level overview of several common ROE models, which can be used as credible benchmarks for determining the cost of equity for Commission-regulated electric utilities. Regardless of the models employed, informed judgment—not just mechanical application of a methodology—should be applied to determine the applicability of individual model results.

All ROE estimation methods, including the DCF approach, are subject to limiting assumptions that may become more or less consistent with market conditions as those conditions change. Any ROE model may be affected by data inputs that fail to reflect investors' true expectations. For that reason, academics and practitioners tend to rely on multiple methods when valuing investments.[80] The results of each model provide useful information that should be used to inform the determination of the market required ROE.

The models discussed below include the CAPM, Risk Premium and Expected Earnings analyses that the Commission has recently considered when determining where within the zone of reasonableness established by the two-step DCF model to set the allowed ROE. In addition, a more general form of the multi-stage DCF model is discussed. The multi-stage DCF model offers an alternative to the two-step DCF method, which would allow for additional flexibility regarding input assumptions.

6.1 The Bond Yield Plus Risk Premium Model

The Bond Yield Plus Risk Premium model, or "Risk Premium" model, is based on the basic financial principle of risk and return, *i.e.*, that investors require greater returns for bearing greater risk. The Risk Premium approach recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on an entity's assets and earnings. The Risk Premium approach specifically recognizes that equity investors require a premium to take on the additional risks associated with equity ownership.

Recall that the cost of equity cannot be directly determined or observed. However, a forward-looking estimate of the cost of equity can be derived based on directly observed bond yields and an estimated Equity Risk Premium over those bond yields. According to Risk Premium theory, the cost of equity equals the expected cost rate for long-term debt capital, plus a risk premium as compensation for residual equity risk.

The traditional Risk Premium formula can be expressed as:

Equation [4]—Traditional Risk Premium Model

$$Cost\ of\ Equity = Bond\ Yield + Equity\ Risk\ Premium$$

[80] *See, e.g.*, Eugene Brigham and Michael Ehrhardt, *Financial Management: Theory and Practice*, 12th Ed. (Mason, OH: South-Western Cengage Learning, 2008), at 346.

A reasonable approach to calculating the risk premium for electric utilities is to use authorized ROEs as the historical measure of the cost of equity.[81] The Commission's past authorized equity returns are an appropriate estimate of the historical ex-ante cost of equity because they reflect the input and analysis of expert witnesses, as well as the Commission's reasoned judgment regarding the forward-looking cost of equity. The Risk Premium model results shown in Charts 1a and 1b (Section 4) use this approach and are consistent with actual authorized ROEs.[82,83]

Academic research has demonstrated that the Equity Risk Premium is inversely related to the level of interest rates; i.e., as interest rates fall, the Equity Risk Premium increases (as discussed in Section 5). Therefore, given the dynamic nature of interest rates, it is not reasonable to rely on a long-term historical average Equity Risk Premium. This is particularly relevant given the low level of current U.S. Treasury yields.

One approach to estimating the forward-looking Equity Risk Premium, therefore, is to perform a regression analysis using the observed Equity Risk Premium over time as the dependent variable and rates on long-term bonds as the independent variable. By applying the regression coefficients to current and expected bond yields, a forward-looking ROE is developed. Using sufficient historical data allows the estimated Equity Risk Premium to reflect market conditions over various economic cycles, with the understanding that, looking forward, investors also will face varying economic and capital market cycles.

Some of the benefits of the Risk Premium model include:

- The model is not dependent on the assumptions required for the DCF model enumerated earlier, including that current market conditions and company policies will persist in perpetuity.
- The bond yield component of the model directly reflects changes in the interest rate environment.
- Trends in the model results tend to be smooth over time, avoiding sharp swings in results that can be associated with the DCF model. As discussed, reducing the uncertainty and volatility of expected future returns is of paramount importance for attracting capital to an essentially irreversible investment in assets with multi-year development cycles and long recovery lives.
- When applied using the Commission's past authorized ROEs as the measure of the cost of equity, the Risk Premium model also provides a measure of consistency in the rate-setting paradigm.

The primary challenge with the implementation of the model is determining a forward-looking Equity Risk Premium, which changes over time.

6.2 Capital Asset Pricing Model

The CAPM analysis is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [5], the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

[81] The model reflects valuation techniques relied on in practice, and is referenced in both academic and industry practitioner literature. *See, e.g.*, CFA Level I Program Curriculum, Volume 4, at 52. *See also* Morin, Roger A., *New Regulatory Finance*, Public Utilities Report, Inc., 2006, at 123-124.

[82] The bond yield component of the model based on then-prevailing level of Moody's Baa-rated public utility long-term debt yields.

[83] See Appendix C for detailed data on the historical Risk Premium analysis results.

Equation [5]—Capital Asset Pricing Model

$$k_e = r_f + \beta\,(r_m - r_f)$$

Where:	k_e	=	*The required market ROE for a security*
	β	=	*The Beta coefficient of the security*
	r_f	=	*The risk-free rate of return*
	r_m	=	*The required return on the market as a whole*

In Equation [5], the term $(r_m - r_f)$ represents the Market Risk Premium ("MRP").[84] According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to their investment portfolio, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

Equation [6]—Beta Coefficient

$$\beta_j = \frac{\sigma_j}{\sigma_m}\,\rho_{j,m}$$

Where:	σ_j	=	*The standard deviation of returns for a company*
	σ_m	=	*The standard deviation of returns for the broad market*
	$\rho_{j,m}$	=	*The correlation of returns between company "j" and the broad market*

Where σ_j is the standard deviation of returns for company "*j*"; σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns between company *j* and the broad market. The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns and the correlation in returns between the subject company and the overall market. Intuitively, higher Beta coefficients indicate that the subject company's returns have been relatively volatile, exaggerating returns on the overall market. If a company has a Beta coefficient of 1.00, it is as risky as the market. The CAPM results in Charts 1a and 1b (section 4) use this approach.[85]

A central theme of the CAPM is that rational investors make investment decisions reflecting an inherent aversion to taking on additional risk without being compensated by additional returns. In the context of the CAPM, risk is defined as the uncertainty, or variability, of returns. The systematic portion of risk is that which can be attributed to the market as a whole, while non-systematic risk is attributable to the idiosyncratic nature of the subject company itself. As noted, systematic risk is measured by the Beta coefficient within the CAPM structure. Because the CAPM assumes that all other risk, *i.e.*, all unsystematic or diversifiable risk, can be eliminated through diversification, only systematic risk is reflected in the cost of equity.

Some of the benefits of the CAPM approach include:

[84] The Market Risk Premium is defined as the incremental return of the market over the risk-free rate.

[85] These results are derived using the 30-day average of the 30-year U.S. Treasury bond yield as the risk-free rate, Beta coefficients reported by Value Line, and a market required rate of return based on a market capitalization-weighted constant growth DCF analysis of the companies in the S&P 500 using consensus growth rates reported by Bloomberg. CAPM results using this methodology have generally been in line with average authorized electric ROEs over the past 10-years. See Appendix B for historical CAPM results.

- The model is a widely taught and commonly used approach to estimate the cost of capital.[86] Research shows that investors' investment decisions are consistent with use of the CAPM to compute the cost of equity.[87]
- The model is not dependent on the assumptions required for the DCF model enumerated earlier, including that current market conditions and company policies will persist in perpetuity.
- The model is premised on the risk/reward relationship that is fundamental to finance and investment theory and, therefore, addresses the *Hope* principle that the allowed return should be commensurate with the relative risk of the investment.
- The model directly incorporates market return data not included in the DCF model, including interest rate levels (through the risk-free rate) and overall market return expectations (through the MRP).

A challenge with implementing the CAPM, however, is that all three inputs (the risk-free rate, the Beta coefficient, and the MRP) vary over time and are sensitive to variations in input assumptions. Model inputs often are the subject of differences in reasoned judgment between analysts in regulatory proceedings. For example, calculation of the Beta coefficient is derived from observable stock price data, but it requires individual judgment regarding the return intervals (*e.g.*, daily, weekly, or monthly returns), measurement period (*e.g.*, one, two or five years), and the benchmark market index to use (*e.g.*, the S&P 500 or the NYSE Index). To the extent there are differences in the assumptions used to estimate the models' inputs, the results can vary significantly. In the context of estimating the appropriate return on the original cost of assets for ratemaking purposes, it is therefore reasonable to gauge whether the assumptions used produce results in line with observed returns on common equity over time.

It is also worth noting that the implied required returns based on the CAPM approach for the overall market have been consistent with the actual earned returns on book equity for the market (*see* Chart 4 above), which averaged 13.24 percent and ranged between approximately 11.5 percent and 15.3 percent over the past 10 years.[88]

6.3 The Expected Earnings Method

The Expected Earnings method calculates the projected returns on book value for comparable electric utilities based on analysts' published projections of electric utility companies' earnings and book equity. One benefit of the Expected Earnings method is that the expected values are directly observable rather than inferred using a mix of market-based pricing data and secondary assumptions about investor expectations (*e.g.*, growth rates).

Another benefit is that the model provides a perspective on the expected return on book value available to comparable companies. For example, the dividend yield, a principal component of the DCF analysis, is a market-derived parameter. Because the DCF model calculates the discount rate that equates the future stream of cash flows to the current market price, it calculates the required return on the market value of the utility's stock (rather than the book value of equity). Similarly, the CAPM calculates a required return on market price (*e.g.*, risk is based on movements in stock prices, and required risk compensation is based on expected returns on a market index). In practice, those returns are applied to the book value of the utility's equity to determine the revenue requirement. The market value, except under very rare circumstances, is not equal to

[86] *See, e.g.*, Ibbotson, *SBBI 2013 Valuation Yearbook*, at 43; Shannon P. Pratt, Roger J. Grabowski, *Cost of Capital: Applications and Examples*, 4th ed. (John Wiley & Sons, Inc., 2010), at 79; Eugene Brigham and Michael Ehrhardt, *Financial Management: Theory and Practice*, 12th ed. (Mason, OH: South-Western Cengage Learning, 2008), at 346.
[87] *See* J. B. Berk and J. H. Binsbergen, "How Do Investors Compute the Discount Rate? They Use the CAPM," *Financial Analysts Journal* 73, No. 2, 2017, pg. 25-32.
[88] Based on rolling five-year average earned ROE.

the book value. Given this mismatch, it is useful to consider a direct measure of the expected return on the book value, versus market value, of electric utility stocks. The approach, therefore, is consistent with the *Hope* and *Bluefield* standards, in that it provides a useful benchmark in assessing whether a proposed return to be applied to a utility's book equity is commensurate with the expected returns available to other investments with comparable risks.

The model also provides a useful perspective because its results are independent from swings in market data. Models such as the DCF and CAPM, in contrast, can be limited by their reliance on a number of assumptions related to investor behavior (*e.g.*, prices reflect DCF-based intrinsic valuations) and efficiency (price volatility is an accurate measure of investors' perceptions of systematic risk).

Although the Expected Earnings approach is a useful method and benchmark, it is important to recognize that the model has limitations. For example, fewer data sources provide forward-looking book value estimates than earnings growth estimates (used in the DCF model) or Beta coefficients (used in the CAPM). In addition, over-reliance on the model could introduce an element of circularity between analysts' expectations and Commission-authorized returns that would become disconnected from market pricing signals.

The Expected Earnings analysis results shown in Charts 1a and 1b are based on Value Line's three-to-five year projections of return on common equity and shares outstanding. Because Value Line calculates the expected earned ROE based on common shares outstanding at the end of the period, the returns are adjusted to reflect growth in common shares. The semi-annual mean results of the Expected Earnings analysis have generally been consistent with average authorized Commission ROEs over the past 10 years.[89]

6.4 The Multi-Stage DCF Model

The two-step DCF method relied on by the Commission uses the constant growth DCF model, but assumes a blended growth rate based on near-term and long-term growth estimates. As previously stated, the general form of the DCF model presented in Equation [1] can be estimated only if one makes simplifying assumptions. A less-restrictive version of the growth assumptions leading to Equation [2] allows for growth to change over time. For example, one might assume a two-stage growth model as follows:

Equation [7]—Two-Stage Growth DCF Model

$$P = \frac{D_0(1+g_a)}{(1+k)} + \frac{D_0(1+g_a)^2}{(1+k)^2} + \cdots + \frac{D_0(1+g_a)^T}{(1+k)^T} + \frac{\left[\frac{D_0(1+g_a)^T(1+g_b)}{(k-g_b)}\right]}{(1+k)^T}$$

Where:

P	=	*The current stock price*
D_0	=	*The current dividend*
k	=	*The discount rate, or required ROE*
g_a	=	*Expected first-stage growth in dividends*
g_b	=	*Expected terminal growth in dividends*
T	=	*The number of years the dividends are expected to grow at* g_a

The bracketed term in Equation [7] represents the expected price of the shares at time T based on a constant growth of dividends at rate g_b after time T in perpetuity. Note that, whereas dividends in Equation [7] are

[89] See Appendix D for historical results.

expected to grow at variable rates, the required ROE k does not change through time. A value for k can be solved from Equation [7] through an iterative calculation process. Also, note that the two-stage growth model in Equation [7] is illustrative only; additional growth stages can be added.

In a sense, the Commission's two-step approach is designed to approximate the two-stage growth model presented in Equation [7]. A drawback of using Equation [7] as a substitute for the Commission two-step approach is that the math becomes a little more complicated, although this problem is easily surmounted by use of a simple spreadsheet. An advantage of using Equation [7] is that one can explicitly specify the two stages of growth by the growth rates and by the length of time the initial growth rate prevails. Such explicit consideration of inputs may be more appropriate under certain market conditions, and may mitigate the concern with specific GDP estimates and the weight given to them.

In addition, using Equation [7] as a starting point, one can consider different approaches to estimation of the expected price of the shares at time T. For example, if one estimates the future price using P/E ratios, Equation [7] becomes:

Equation [8]

$$P = \frac{D_0(1+g_a)}{(1+k)} + \frac{D_0(1+g_a)^2}{(1+k)^2} + \cdots + \frac{D_0(1+g_a)^T}{(1+k)^T} + \frac{\left[\frac{P}{E} E_0 \, (1+g_a)^T\right]}{(1+k)^T}$$

	P	=	*The current stock price*
	D_0	=	*The current dividend*
	E_0	=	*The current earnings per share (EPS)*
Where:	k	=	*The discount rate, or required ROE*
	g_a	=	*Expected first-stage growth in dividends*
	T	=	*The number of years the dividends are expected to grow at g_a*

The use of different terminal value assumptions, for example, by reference to trading multiples like the P/E ratio, may produce ROE estimates more consistent with observable market conditions.

An important benefit of the multi-stage DCF model is that it specifically addresses certain limiting assumptions of the constant growth DCF model. For example, it has the ability to recognize that dividend payout ratios may decrease during periods of increasing capital expenditures. Another advantage of the multi-stage DCF model is that internal assumptions of the model, such as the implied price-to-earnings growth ratio, can be checked for reasonableness against observable market data.[90]

6.5 Summary of Benefits of Alternative ROE Models and Recommendation

There is no question that equity analysts and investors use multiple methods to develop their return requirements. The CAPM, Risk Premium, Expected Earnings approaches, and the multi-stage form of the DCF model provide useful measures of required return that reflect the types of analysis used in practice. Data for the models can be obtained from widely accessible data sources and can be implemented without undue complexity.

[90] The price-to-earnings growth ratio (sometimes referred to as the "PEG ratio") is calculated by dividing the P/E ratio by the expected growth rate. The PEG ratio is a commonly referenced financial valuation metric that recognizes price is a function of both current earnings and growth.

In Opinion No. 531, the Commission found it necessary to consider alternative ROE benchmarks in establishing the just and reasonable ROE. Regardless of the models employed, informed judgment—not just mechanical application of a methodology—should be applied to determine the reasonableness and applicability of individual model results in the context of the capital market environment using observable benchmarks, such as the returns allowed by state commissions.

In addition to the alternative ROE methods discussed earlier, there are a number of extensions to the models that could be explored and potentially used (such as the multi-factor form of the CAPM, the empirical form of the CAPM, the build-up method of Risk Premium analysis, or the adjusted present value form of the DCF approach). Extensions to the standard forms of the ROE models may allow some of the underlying assumptions to be relaxed, and the inputs to be adapted to varying market conditions. Research into additional alternative methods may be warranted.

7: CONCLUSION AND SUMMARY OF RECOMMENDATIONS

Transmission is integral to our nation's energy infrastructure, providing value to customers by delivering reliable, affordable, and increasingly clean energy needed to power their homes, their businesses, and their communities. Maintaining, expanding, and enhancing the transmission system requires ongoing investment, and it is imperative that the Commission foster this investment by providing stable, predictable, and adequate returns to the investors and owners of the transmission infrastructure.

Despite the Commission's valued efforts in Opinion No. 531 to provide stable, predictable, and adequate returns for transmission investment, shortcomings in the Commission's prevailing two-step DCF method for determining the allowed ROE for electric transmission companies is leading to estimates below other widely accepted alternative estimation models and market indicators. This, in turn, undermines investment in transmission infrastructure and investor confidence, and it constrains access to external sources of capital.

This paper recommends the following modifications to temper, but not eliminate, existing shortcomings in the current method of employing the two-step DCF approach. The Commission should:

- Broaden the proxy group by modifying existing screening criteria and expanding the universe of companies eligible for inclusion.
- Consider additional sources of published analyst growth rate estimates when determining the zone of reasonableness.
- Reduce the weight currently given to the GDP growth rate in the application of the two-step DCF method, *i.e.* from 1/3 to 1/5, and incorporate an inflation-adjusted long-term GDP estimate such as Morningstar's approach in the *Ibbotson SBBI Valuation Yearbook*; in the alternative, remove GDP from the application of the DCF model altogether.
- Re-examine the thresholds used to determine which DCF results do not pass tests of economic logic, and ensure the thresholds applied appropriately account for current capital market conditions.

Changes such as broadening the group of comparison companies used as proxies, using additional estimates of both short-term and long-term growth, and updating the Commission's test for eliminating illogical low-end and high-end results would temper existing shortcomings in the current method of employing the two-step DCF approach.

Although the DCF model is theoretically sound, its assumptions are quite restrictive and rarely hold outside of the theoretical realm. These assumptions can engender unreliable results, particularly when investor expectations are not consistent with the DCF model's assumption that current market conditions will persist. Practitioners and academics recognize that financial models simply are tools to be used in the ROE estimation process and that the strict adherence to any single approach, or to the specific results of any single approach, can lead to misleading conclusions.

As such, the Commission's recent use of alternative ROE models (such as the CAPM, Risk Premium, and Expected Earning approaches) and market indicators to benchmark and check the reasonableness of the results of the DCF approach is reasonable and should be continued. This position is consistent with the *Hope and Bluefield* finding that the method employed is not controlling when determining just and reasonable rate levels. Benchmarking against additional models would help to ensure rates are set at levels supportive of the Commission's stated policy goals and meet well-established capital attraction standards. Importantly, regardless of the models employed, informed judgment must be applied to determine the applicability of individual model results in the context of the capital market environment.

APPENDIX A—TWO-STEP DCF MODEL RESULTS (BLOOMBERG GROWTH RATES)

TICKER	Dec-07	Jun-08	Dec-08	Jun-09	Dec-09	Jun-10	Dec-10	Jun-11	Dec-11	Jun-12	Dec-12	Jun-13	Dec-13	Jun-14	Dec-14	Jun-15	Dec-15	Jun-16	Dec-16	Apr-17
AEE	12.19%	11.08%	13.04%	11.22%	10.23%	6.26%	5.14%	4.94%	3.99%	3.73%	3.71%	8.96%	8.76%	10.53%	10.22%	10.14%	10.31%	9.13%	8.99%	8.88%
AEP	9.73%	9.23%	9.80%	10.79%	9.44%	8.79%	8.95%	9.71%	8.95%	9.29%	8.93%	8.57%	9.06%	8.84%	9.19%	8.62%	8.97%	8.62%	8.66%	8.09%
ALE	10.46%	10.99%	11.19%	12.99%	11.97%	10.94%	9.86%	9.56%	9.74%	9.74%	9.85%	9.56%	N/A	N/A	N/A	9.42%	9.30%	9.33%	9.14%	8.86%
AGR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	11.17%	11.92%
AVA	8.71%	10.39%	10.75%	11.95%	12.90%	10.84%	9.47%	9.77%	9.41%	9.39%	9.21%	9.13%	8.68%	9.05%	N/A	N/A	8.86%	8.34%	8.82%	9.05%
BKH	9.23%	9.39%	10.86%	12.49%	11.27%	10.65%	10.30%	9.59%	10.35%	10.03%	9.89%	9.05%	N/A	8.96%	9.15%	6.11%	8.13%	8.86%	7.63%	9.66%
CMS	6.74%	7.98%	9.36%	10.24%	9.24%	10.49%	11.16%	9.81%	9.84%	9.71%	9.60%	9.35%	9.34%	9.32%	9.18%	8.80%	8.90%	8.61%	8.46%	8.79%
CNP	10.33%	10.11%	13.79%	13.25%	12.35%	9.83%	11.77%	10.02%	9.59%	9.25%	9.16%	9.29%	8.36%	9.20%	9.53%	10.50%	10.69%	10.48%	9.52%	9.65%
D	11.84%	10.86%	11.28%	10.94%	8.84%	8.41%	9.29%	8.45%	8.90%	9.67%	9.63%	9.67%	9.10%	8.97%	9.40%	9.22%	9.27%	9.70%	9.38%	9.15%
DTE	9.33%	10.20%	11.05%	11.73%	10.27%	9.36%	9.47%	9.41%	9.63%	9.18%	9.00%	8.41%	8.43%	8.75%	8.77%	8.44%	8.87%	8.79%	8.12%	8.88%
DUK	9.97%	9.95%	10.14%	10.93%	10.31%	8.13%	9.79%	10.01%	9.86%	9.23%	9.26%	8.95%	8.74%	8.97%	9.02%	8.93%	8.64%	8.94%	8.51%	9.25%
ED	9.35%	9.12%	9.90%	10.20%	10.42%	9.75%	9.43%	8.59%	8.22%	7.84%	7.73%	7.45%	6.22%	8.49%	7.86%	7.66%	7.38%	7.44%	7.30%	7.34%
EE	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	9.61%	8.43%	9.92%	N/A	9.24%	9.19%	9.16%	N/A	N/A	N/A	N/A	8.45%
EIX	9.43%	10.31%	10.38%	9.58%	8.51%	6.01%	5.97%	6.80%	5.58%	4.26%	8.42%	7.54%	7.25%	7.53%	7.03%	8.44%	7.37%	8.19%	8.20%	7.53%
ES	10.18%	9.37%	9.55%	10.38%	10.87%	10.60%	9.54%	10.08%	9.74%	8.45%	9.79%	10.12%	9.73%	9.36%	9.35%	9.15%	9.38%	9.38%	9.11%	8.81%
ETR	12.45%	12.54%	11.38%	11.61%	8.22%	8.19%	7.52%	7.07%	5.99%	7.79%	7.69%	7.26%	5.31%	5.76%	6.95%	9.72%	5.58%	6.06%	2.86%	4.40%
EXC	9.91%	9.44%	9.29%	8.51%	7.38%	5.29%	5.55%	6.79%	6.70%	5.62%	6.14%	5.51%	4.21%	8.28%	8.71%	9.85%	8.96%	8.45%	7.39%	8.13%
FE	10.49%	9.48%	11.00%	11.87%	8.58%	9.71%	9.60%	9.26%	8.30%	6.57%	9.12%	10.07%	9.16%	9.31%	4.16%	5.84%	4.83%	4.74%	5.00%	6.26%
HE	8.00%	8.61%	8.29%	10.67%	15.97%	13.82%	17.97%	12.65%	12.52%	10.53%	10.04%	10.02%	11.78%	9.21%	8.70%	8.04%	8.50%	8.17%	8.25%	7.99%
IDA	8.52%	9.41%	9.11%	9.74%	9.08%	8.19%	8.07%	7.83%	7.30%	7.77%	7.58%	7.42%	7.49%	7.36%	7.32%	7.22%	7.30%	7.00%	6.24%	6.23%
LNT	8.17%	9.43%	10.42%	10.74%	10.42%	12.21%	9.41%	9.99%	9.88%	9.70%	9.93%	9.78%	9.23%	8.58%	8.80%	9.08%	9.11%	9.67%	9.49%	9.03%
MGEE	N/A	N/A	N/A	N/A	9.00%	9.17%	8.77%	7.90%	7.18%	7.58%	7.29%	7.11%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NWE	N/A	N/A	N/A	13.77%	12.67%	11.81%	10.94%	10.84%	10.22%	10.43%	9.47%	9.08%	9.76%	10.99%	9.47%	8.37%	8.48%	8.28%	8.08%	7.06%
OGE	7.54%	7.84%	8.52%	10.68%	10.23%	8.83%	9.38%	9.26%	9.50%	8.69%	7.76%	7.91%	7.21%	8.05%	8.50%	8.62%	9.09%	8.15%	8.99%	8.77%
OTTR	8.07%	9.54%	11.62%	15.14%	14.38%	15.05%	10.84%	16.84%	17.37%	16.89%	16.41%	9.75%	N/A	N/A	11.11%	N/A	N/A	N/A	8.36%	8.75%
PCG	10.26%	10.45%	10.68%	10.63%	10.58%	10.77%	10.03%	9.76%	8.35%	8.46%	8.45%	9.05%	7.75%	10.43%	10.45%	8.93%	7.69%	7.88%	7.81%	8.98%
PEG	13.25%	12.03%	8.82%	8.95%	8.64%	6.64%	6.66%	7.87%	8.14%	5.71%	5.97%	5.18%	6.30%	8.94%	7.87%	8.81%	8.00%	8.14%	6.92%	6.92%
PNM	11.59%	19.15%	9.48%	12.20%	22.78%	13.28%	12.31%	11.50%	11.03%	7.95%	8.31%	8.90%	8.46%	8.93%	7.60%	7.70%	7.83%	7.57%	8.98%	8.94%
PNW	9.60%	8.13%	11.31%	12.14%	12.68%	11.57%	11.03%	9.32%	10.58%	10.17%	8.19%	8.42%	8.50%	8.61%	8.55%	8.76%	8.64%	8.15%	8.36%	8.20%
POR	11.76%	9.94%	10.20%	11.09%	10.59%	10.10%	10.37%	8.99%	9.33%	9.13%	8.19%	9.52%	8.91%	8.35%	9.22%	8.39%	8.03%	9.02%	8.67%	8.00%
PPL	12.30%	14.23%	13.64%	13.54%	12.41%	9.33%	9.82%	9.23%	15.20%	0.87%	10.27%	7.97%	10.11%	10.79%	9.26%	8.01%	8.13%	9.07%	5.62%	7.01%
SCG	9.23%	9.63%	10.07%	10.79%	10.58%	9.40%	9.55%	9.63%	9.43%	8.93%	9.03%	8.30%	9.81%	9.08%	9.69%	9.44%	9.15%	8.94%	8.94%	8.96%
SO	9.68%	9.93%	9.91%	10.65%	10.08%	10.46%	9.83%	10.00%	10.16%	9.59%	9.39%	9.16%	9.39%	8.76%	8.88%	8.96%	9.15%	8.89%	8.74%	9.04%
SRE	8.27%	9.44%	9.13%	9.22%	8.73%	9.12%	10.34%	9.39%	10.59%	10.49%	9.75%	9.07%	9.12%	8.91%	9.04%	9.48%	12.43%	9.29%	10.08%	9.41%
VVC	8.29%	9.55%	10.59%	13.51%	10.54%	10.62%	9.92%	10.46%	10.35%	9.70%	10.41%	9.12%	9.04%	8.29%	8.38%	8.66%	8.59%	8.28%	8.33%	8.30%
WEC	8.67%	9.87%	10.86%	10.56%	10.52%	10.42%	10.48%	9.54%	9.20%	8.00%	7.89%	8.05%	8.58%	8.43%	8.95%	7.81%	9.27%	8.64%	9.07%	9.46%
XEL	9.85%	10.45%	9.60%	10.65%	10.33%	10.44%	9.83%	9.39%	8.87%	8.94%	8.76%	8.50%	8.84%	8.85%	8.59%	8.74%	8.32%	8.92%	8.82%	8.94%

Zone of Reasonableness Summary

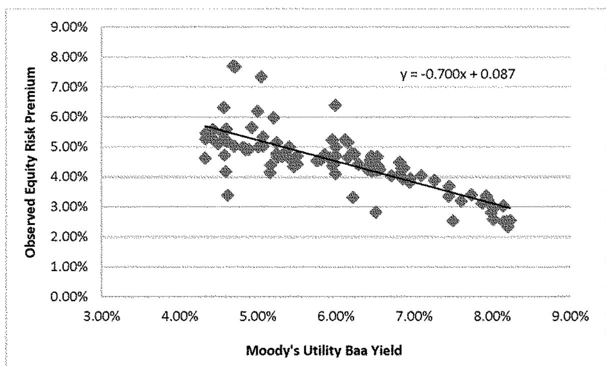
High Result	13.25%	14.23%	13.79%	15.14%	15.97%	15.05%	12.31%	16.84%	17.37%	16.89%	16.41%	10.12%	11.78%	10.99%	11.11%	10.50%	12.43%	10.48%	11.17%	11.92%
High Company	PEG	PPL	CNP	OTTR	HE	OTTR	PNM	OTTR	OTTR	OTTR	OTTR	ES	HE	NWE	OTTR	CNP	SRE	CNP	AGR	AGR
Low Result	7.54%	7.84%	8.82%	8.95%	7.38%	8.13%	7.52%	7.07%	6.70%	6.57%	5.97%	7.11%	6.30%	7.36%	6.95%	5.84%	7.30%	6.06%	5.62%	6.23%
Low Company	OGE	OGE	PEG	PEG	EXC	DUK	ETR	ETR	EXC	FE	PEG	MGEE	PEG	IDA	ETR	FE	IDA	ETR	PPL	IDA
Midpoint	10.40%	11.04%	11.30%	12.04%	11.67%	11.59%	9.92%	11.96%	12.04%	11.73%	11.19%	8.62%	9.04%	9.17%	9.03%	8.17%	9.86%	8.27%	8.40%	9.07%
Median	9.70%	9.75%	10.42%	10.93%	10.37%	10.42%	9.82%	9.58%	9.61%	9.23%	9.12%	9.05%	8.91%	8.94%	8.98%	8.75%	8.86%	8.63%	8.66%	8.81%
Low-End Screen	7.43%	7.69%	8.77%	8.78%	7.33%	7.16%	6.76%	6.92%	6.21%	6.03%	5.68%	5.72%	6.24%	5.89%	5.70%	5.65%	6.41%	5.94%	5.40%	5.63%

APPENDIX B—CAPITAL ASSET PRICING MODEL RESULTS

	Beta, as of:																			
TICKER	Dec-07	Jun-08	Dec-08	Jun-09	Dec-09	Jun-10	Dec-10	Jun-11	Dec-11	Jun-12	Dec-12	Jun-13	Dec-13	Jun-14	Dec-14	Jun-15	Dec-15	Jun-16	Dec-16	Apr-17
AEE	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.75	0.75	0.75	0.75	0.75	0.65	0.70
AEP	0.95	0.85	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.65	0.65	0.70	0.65	0.70	0.70	0.70	0.70	0.65	0.65
ALE	0.95	0.90	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.80	0.80	0.80	0.75	0.75	0.80
AGR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AVA	1.00	0.95	0.85	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.80	0.80	0.80	0.80	0.75	0.70	0.70
BKH	1.10	0.90	0.85	0.80	0.80	0.80	0.80	0.80	0.85	0.85	0.80	0.80	0.85	0.90	0.90	0.95	0.95	0.90	0.90	0.85
CMS	1.35	1.05	0.95	0.80	0.80	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.70	0.75	0.70	0.75	0.75	0.70	0.65	0.65
CNP	0.95	0.95	0.90	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.75	0.80	0.80	0.75	0.75	0.80	0.85	0.85	0.85	0.85
D	0.75	0.80	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.65	0.70
DTE	0.80	0.80	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.80	0.75	0.75	0.75	0.75	0.70	0.65	0.65
DUK	NMF	NMF	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.60	0.60	0.65	0.60	0.60	0.60	0.65	0.60	0.60	0.60
ED	0.75	0.75	0.65	0.65	0.65	0.65	0.65	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.55	0.55	0.55
EE	0.80	0.90	0.95	0.80	0.75	0.75	0.75	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.70	0.75
EIX	1.05	0.85	0.85	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.75	0.75	0.75	0.80	0.75	0.75	0.70	0.70	0.65	0.60
ES	0.80	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.70	0.70
ETR	0.85	0.85	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.65	0.65
EXC	0.90	0.85	0.90	0.85	0.85	0.85	0.85	0.85	0.85	0.80	0.80	0.80	0.75	0.70	0.70	0.70	0.70	0.65	0.65	0.70
FE	0.85	0.80	0.85	0.85	0.80	0.80	0.80	0.80	0.80	0.80	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.65	0.65
HE	0.70	0.70	0.75	0.60	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.85	0.80	0.80	0.80	0.75	0.70	0.70
IDA	1.00	0.90	0.85	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.80	0.80	0.80	0.80	0.80	0.75	0.75
LNT	0.80	0.80	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.70	0.70	0.75	0.75	0.80	0.80	0.80	0.75	0.70	0.70
MGEE	0.95	0.95	0.70	0.65	0.65	0.65	0.65	0.60	0.60	0.60	0.60	0.60	0.65	0.70	0.70	0.75	0.75	0.70	0.70	0.70
NWE	N/A	NMF	NMF	NMF	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.65
OGE	0.85	0.90	0.75	0.75	0.75	0.75	0.75	0.75	0.80	0.80	0.75	0.75	0.85	0.85	0.90	0.90	0.95	0.95	0.90	0.95
OTTR	0.95	0.95	0.90	0.95	0.95	0.95	0.95	0.95	0.90	0.90	0.90	0.90	0.95	0.90	0.90	0.90	0.85	0.80	0.85	0.85
PCG	0.95	0.80	0.85	0.60	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.50	0.55	0.60	0.65	0.65	0.65	0.70	0.65	0.65
PEG	0.95	0.90	0.85	0.80	0.80	0.80	0.80	0.75	0.80	0.80	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.70	0.70
PNM	0.95	0.85	0.90	0.85	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.90	0.95	0.85	0.85	0.85	0.80	0.75	0.70
PNW	1.00	0.80	0.75	0.70	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.70	0.70	0.75	0.75	0.70	0.70
POR	NMF	0.85	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.70	0.70
PPL	0.90	0.90	0.80	0.70	0.70	0.70	0.70	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.60	0.65	0.70	0.70	0.70	0.70
SCG	0.85	0.85	0.70	0.70	0.65	0.65	0.70	0.65	0.70	0.70	0.65	0.65	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.65
SO	0.70	0.70	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.60	0.55	0.60	0.60	0.55	0.55	0.55
SRE	1.00	0.90	0.90	0.90	0.85	0.85	0.85	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.75	0.80	0.80	0.85	0.80	0.80
VVC	0.90	0.90	0.85	0.75	0.75	0.70	0.70	0.70	0.70	0.75	0.70	0.70	0.70	0.75	0.80	0.80	0.75	0.75	0.75	0.75
WEC	0.85	0.80	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.60	0.60	0.65	0.65	0.65	0.70	0.70	0.65	0.60	0.60
XEL	1.05	0.75	0.75	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.60	0.65	0.65	0.70	0.65	0.65	0.65	0.60	0.60
Proxy Group:																				
Mean Beta	0.91	0.85	0.78	0.73	0.73	0.73	0.73	0.72	0.73	0.73	0.71	0.71	0.73	0.74	0.74	0.75	0.75	0.73	0.70	0.70
Median Beta	0.90	0.85	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.73	0.70	0.70
High Beta	1.35	1.05	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.90	0.95	0.95	0.95	0.90	0.95
Low Beta	0.70	0.70	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.50	0.55	0.60	0.55	0.60	0.60	0.55	0.55	0.55
Market:																				
Risk-Free Rate	4.49%	4.66%	3.02%	4.48%	4.44%	4.12%	4.37%	4.24%	2.97%	2.73%	2.86%	3.34%	3.87%	3.40%	2.87%	3.07%	2.97%	2.50%	3.08%	2.96%
Market Return	14.36%	15.06%	14.03%	12.32%	11.85%	13.50%	13.65%	12.77%	13.07%	12.94%	12.98%	13.75%	13.81%	13.49%	13.42%	13.28%	13.56%	13.13%	12.84%	13.33%
MRP	9.87%	10.39%	11.01%	7.84%	7.41%	9.38%	9.28%	8.53%	10.10%	10.21%	10.12%	10.41%	9.94%	10.08%	10.56%	10.22%	10.59%	10.63%	9.75%	10.37%
CAPM ROE Result:																				
Mean	13.46%	13.51%	11.66%	10.23%	9.87%	10.96%	11.15%	10.40%	10.32%	10.16%	10.05%	10.70%	11.08%	10.84%	10.64%	10.68%	10.92%	10.27%	9.88%	10.21%
Median	13.37%	13.50%	11.28%	9.97%	9.63%	10.69%	10.86%	10.21%	10.04%	9.88%	9.95%	10.63%	10.83%	10.97%	10.78%	10.73%	10.92%	10.21%	9.91%	10.22%
Midpoint	14.61%	13.76%	11.28%	10.36%	10.00%	11.16%	11.33%	10.64%	10.54%	10.39%	10.45%	10.89%	11.33%	11.22%	10.52%	10.98%	11.18%	10.48%	10.15%	10.74%

Note: Market return based on market capitalization weighted DCF of S&P 500 using analyst growth rate projections from Bloomberg

APPENDIX C—BOND YIELD PLUS RISK PREMIUM RESULTS



Bond Yield Plus Risk Premium Using FERC Electric Authorized ROEs and Baa Bond Yields

	Dec-07	Jun-08	Dec-08	Jun-09	Dec-09	Jun-10	Dec-10	Jun-11	Dec-11
Regression Slope	-0.700								
Regressoin Constant	0.087								
Baa yield (6-month)	6.38%	6.50%	7.11%	8.01%	7.04%	6.20%	5.93%	5.90%	5.57%
Equity Risk Premium	4.26%	4.17%	3.75%	3.12%	3.80%	4.39%	4.58%	4.60%	4.83%
ROE Estimate	10.64%	10.68%	10.86%	11.13%	10.84%	10.59%	10.51%	10.50%	10.40%

	Jun-12	Dec-12	Jun-13	Dec-13	Jun-14	Dec-14	Jun-15	Dec-15	Jun-16	Dec-16	Apr-17
Regression Slope											
Regressoin Constant											
Baa yield (6-month)	5.08%	4.88%	4.63%	5.01%	5.11%	4.75%	4.61%	5.07%	5.31%	4.49%	4.47%
Equity Risk Premium	5.17%	5.31%	5.49%	5.22%	5.15%	5.41%	5.50%	5.18%	5.01%	5.59%	5.60%
ROE Estimate	10.25%	10.19%	10.12%	10.23%	10.26%	10.15%	10.11%	10.25%	10.32%	10.07%	10.07%

APPENDIX D—EXPECTED EARNINGS ANALYSIS RESULTS

TICKER	Dec-07	Jun-08	Dec-08	Jun-09	Dec-09	Jun-10	Dec-10	Jun-11	Dec-11	Jun-12	Dec-12	Jun-13	Dec-13	Jun-14	Dec-14	Jun-15	Dec-15	Jun-16	Dec-16	Apr-17
AEE	9.17%	9.71%	10.72%	8.20%	8.18%	6.62%	7.14%	7.12%	7.12%	7.10%	7.11%	8.67%	8.67%	9.72%	9.72%	10.26%	10.72%	9.66%	9.66%	10.20%
AEP	12.94%	12.41%	10.86%	10.79%	10.80%	10.28%	10.79%	10.80%	10.79%	10.25%	9.72%	10.24%	10.75%	10.21%	10.21%	10.73%	10.22%	9.69%	10.72%	11.22%
ALE	10.84%	9.93%	8.83%	9.33%	9.33%	8.13%	9.17%	9.70%	9.77%	10.25%	10.30%	9.77%	9.36%	9.20%	9.27%	9.18%	9.19%	8.67%	9.18%	9.20%
AGR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.52%	5.04%
AVA	8.71%	8.70%	8.70%	8.16%	8.70%	9.18%	9.20%	9.17%	9.16%	9.18%	8.65%	8.64%	8.64%	9.16%	8.65%	9.16%	9.14%	9.16%	8.65%	8.12%
BKH	9.72%	9.74%	7.63%	8.63%	9.69%	8.13%	7.70%	8.13%	7.60%	8.63%	8.11%	9.18%	9.19%	9.70%	9.19%	8.67%	9.71%	11.01%	11.02%	10.97%
CMS	12.81%	12.42%	12.42%	11.35%	10.81%	11.88%	12.87%	12.89%	12.90%	12.88%	12.87%	13.41%	13.43%	13.91%	13.97%	13.93%	13.93%	13.96%	13.98%	13.97%
CNP	21.46%	17.71%	18.31%	18.28%	17.22%	16.14%	14.62%	11.77%	11.76%	11.73%	12.84%	13.31%	14.89%	13.17%	15.25%	12.21%	13.43%	15.75%	15.73%	17.37%
D	15.82%	15.86%	15.83%	15.70%	16.24%	15.03%	15.01%	14.47%	14.46%	14.99%	14.95%	16.59%	15.66%	15.65%	15.23%	18.18%	18.16%	18.82%	19.44%	18.81%
DTE	9.05%	9.15%	9.14%	9.70%	10.25%	9.23%	9.20%	9.16%	9.19%	9.70%	9.77%	9.27%	9.79%	10.29%	9.80%	10.31%	10.31%	10.25%	10.79%	10.78%
DUK	8.11%	8.12%	8.11%	8.08%	8.07%	8.09%	8.09%	8.61%	8.62%	9.14%	8.10%	8.09%	8.11%	8.11%	8.11%	8.11%	8.09%	8.09%	8.60%	8.59%
ED	8.70%	9.16%	8.64%	9.17%	9.69%	9.63%	9.70%	9.68%	9.68%	9.68%	9.17%	9.16%	9.16%	8.63%	9.15%	9.15%	9.15%	8.64%	8.65%	8.65%
EE	10.38%	9.37%	9.90%	9.80%	9.87%	9.31%	9.88%	11.23%	11.75%	11.69%	10.71%	10.67%	10.74%	10.19%	10.18%	9.19%	9.71%	8.65%	9.19%	9.69%
EIX	10.87%	11.97%	11.97%	11.33%	11.90%	9.22%	8.70%	8.18%	8.17%	9.21%	9.19%	11.35%	11.33%	11.33%	11.34%	11.82%	11.84%	11.79%	11.79%	11.25%
ES	10.90%	10.05%	9.59%	8.92%	9.80%	9.26%	10.33%	10.34%	10.86%	9.71%	9.70%	9.69%	9.69%	9.69%	9.70%	10.22%	9.70%	9.68%	9.69%	10.21%
ETR	14.56%	15.84%	14.53%	14.60%	14.98%	13.82%	11.78%	11.79%	10.72%	9.60%	9.59%	9.61%	9.66%	10.20%	10.71%	9.13%	9.11%	11.23%	9.64%	10.14%
EXC	25.16%	26.13%	25.51%	24.33%	19.70%	15.93%	14.24%	14.69%	15.19%	12.13%	12.64%	9.72%	8.14%	9.19%	9.79%	9.27%	9.80%	10.33%	9.81%	9.77%
FE	13.99%	16.16%	15.61%	14.44%	14.93%	12.84%	11.19%	10.18%	10.19%	10.69%	10.16%	8.60%	9.19%	8.18%	8.69%	8.69%	9.22%	9.24%	8.81%	8.77%
HE	11.12%	10.64%	11.19%	10.66%	10.67%	11.28%	10.74%	10.89%	10.82%	9.70%	10.53%	9.50%	8.40%	9.76%	10.28%	9.75%	9.72%	9.20%	9.21%	9.17%
IDA	7.20%	7.67%	7.66%	7.76%	7.77%	8.75%	8.75%	8.72%	8.72%	8.22%	8.68%	8.69%	8.69%	8.16%	8.66%	8.65%	8.65%	9.18%	9.18%	9.17%
LNT	10.81%	10.36%	10.82%	10.77%	10.23%	11.76%	12.28%	12.25%	11.72%	10.67%	11.22%	11.29%	11.78%	11.76%	12.24%	11.68%	11.64%	12.66%	12.66%	13.18%
MGEE	14.17%	12.22%	12.22%	12.07%	12.08%	12.23%	12.23%	12.16%	12.09%	10.78%	11.28%	11.52%	12.27%	13.41%	13.93%	13.41%	13.09%	13.32%	13.34%	12.87%
NWE	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	10.22%	9.56%	9.71%	9.67%	9.67%	10.21%	10.20%	10.21%	10.21%	9.67%
OGE	12.28%	11.97%	12.02%	12.04%	11.97%	12.00%	12.98%	12.46%	12.45%	11.93%	11.56%	11.37%	12.31%	12.40%	12.38%	11.25%	11.22%	12.22%	11.71%	12.22%
OTTR	10.84%	10.31%	9.22%	8.77%	9.26%	9.73%	7.75%	9.28%	7.25%	10.31%	10.88%	11.21%	11.87%	12.85%	12.86%	12.84%	12.84%	10.85%	10.36%	9.90%
PCG	11.36%	11.81%	11.87%	13.08%	12.51%	12.47%	12.47%	11.92%	11.92%	10.76%	10.28%	9.19%	8.68%	8.68%	8.68%	9.74%	10.88%	10.32%	11.30%	10.29%
PEG	15.26%	15.23%	17.74%	16.65%	16.11%	12.97%	12.99%	12.90%	12.89%	11.28%	11.25%	10.20%	10.75%	10.75%	10.75%	10.74%	11.28%	11.26%	11.19%	11.76%
PNM	7.68%	5.52%	4.53%	5.09%	5.61%	6.11%	6.11%	6.68%	6.68%	9.19%	9.19%	8.67%	9.19%	9.66%	9.66%	9.67%	9.67%	9.64%	9.64%	9.59%
PNW	8.60%	8.11%	8.14%	9.22%	9.30%	9.28%	9.27%	9.27%	9.28%	9.23%	9.24%	10.21%	10.23%	9.74%	9.74%	9.74%	10.26%	10.19%	10.20%	10.21%
POR	8.75%	9.34%	9.43%	9.26%	8.71%	8.81%	8.82%	8.66%	9.19%	9.18%	9.16%	8.14%	8.27%	9.19%	9.35%	9.20%	9.71%	9.19%	9.17%	9.67%
PPL	24.44%	22.99%	21.80%	23.10%	20.39%	15.87%	12.10%	12.68%	12.69%	11.59%	12.09%	11.41%	10.80%	10.71%	10.71%	10.24%	11.83%	15.53%	13.83%	14.53%
SCG	11.23%	10.87%	10.96%	10.89%	10.93%	10.28%	10.43%	9.91%	9.43%	9.95%	9.97%	9.90%	9.89%	10.37%	10.39%	9.76%	10.30%	10.28%	10.27%	10.28%
SO	13.37%	14.48%	14.47%	14.42%	14.38%	13.94%	13.44%	13.44%	13.45%	12.95%	12.90%	12.85%	12.34%	12.82%	12.83%	13.73%	13.75%	12.68%	11.20%	11.20%
SRE	12.55%	13.97%	13.98%	12.53%	12.56%	11.46%	10.27%	11.37%	10.85%	11.30%	11.80%	10.76%	11.27%	11.79%	11.80%	12.85%	12.86%	13.92%	14.17%	13.02%
VVC	10.71%	10.65%	11.80%	10.34%	11.29%	10.77%	10.82%	10.77%	11.27%	12.27%	11.26%	11.64%	11.88%	14.24%	14.25%	14.70%	15.21%	12.84%	13.36%	12.83%
WEC	11.82%	12.38%	12.86%	12.34%	11.83%	12.86%	13.35%	14.18%	14.16%	14.16%	13.73%	14.22%	15.65%	15.59%	15.63%	16.06%	11.20%	11.20%	11.20%	11.19%
XEL	10.73%	11.27%	10.74%	10.76%	10.76%	10.30%	10.32%	10.27%	10.26%	10.29%	10.30%	10.27%	10.25%	10.11%	10.24%	10.22%	10.21%	10.71%	11.22%	10.70%
Proxy Group:																				
Mean	12.18%	12.06%	11.94%	11.73%	11.61%	10.96%	10.71%	10.74%	10.66%	10.58%	10.53%	10.46%	10.57%	10.78%	10.92%	10.91%	11.00%	11.11%	10.93%	10.92%
Median	10.90%	10.87%	10.96%	10.77%	10.80%	10.30%	10.43%	10.77%	10.79%	10.29%	10.29%	10.05%	10.06%	10.19%	10.23%	10.22%	10.28%	10.32%	10.36%	10.28%
Low	7.20%	5.52%	4.53%	5.09%	5.61%	6.11%	6.11%	6.68%	6.68%	7.10%	7.11%	8.09%	8.11%	8.11%	8.11%	8.11%	8.09%	8.09%	5.52%	5.04%
High	25.16%	26.13%	25.51%	24.33%	20.39%	16.14%	15.01%	14.69%	15.19%	14.99%	14.95%	16.59%	15.66%	15.65%	15.63%	18.18%	18.16%	18.82%	19.44%	18.81%
Midpoint	16.18%	15.83%	15.02%	14.71%	13.00%	11.13%	10.56%	10.69%	10.94%	11.05%	11.03%	12.34%	11.88%	11.88%	11.87%	13.14%	13.13%	13.45%	12.48%	11.92%
Zone of Reasonableness Summary																				
Mean	11.22%	11.41%	11.71%	11.61%	11.28%	11.24%	10.84%	10.86%	10.66%	10.58%	10.53%	10.46%	10.57%	10.78%	10.92%	10.70%	10.79%	10.89%	10.69%	10.87%
Median	10.87%	10.76%	11.49%	10.89%	10.78%	10.77%	10.58%	10.79%	10.79%	10.29%	10.29%	10.05%	10.06%	10.19%	10.23%	10.22%	10.26%	10.32%	10.32%	10.28%

Mr. MOELLER. In addition there are serial complaints, the 15-month issue, I mentioned. There's the capping of transmission incentives which, I think, is probably counter to the intent of Congress from the 2005 Act.

And then the ongoing very general issue of cost allocation on these multi-decade assets where figuring out who pays how much, there's a lot of art and science in that because flows change over the decades. But adding more certainty, very generally, to that will improve the investment climate.

The CHAIRMAN. Very good. Thank you both.

Senator Cantwell.

Senator CANTWELL. Thank you, Madam Chair.

I had a very interesting meeting earlier this week when the National Association of Office Parks came to visit and their whole focus was energy efficiency. I kept thinking, really? They want infrastructure investment, of course, but they kept going on and on about energy efficiency and how the building standards help us get the energy efficiency.

We described to them how much we had worked here as a Committee to get those kinds of new things in place and passed the bill over to the House and they still hadn't supported it. Even now as we talk about moving another energy bill back over and getting the House to agree with us, we still have stumbling blocks with our House colleagues who basically don't see the advantages of energy efficiency from a building code perspective.

I said, I don't know how to break through. And the gentleman said, "just tell them we don't want our buildings to suck."

[Laughter.]

I thought, okay, you are right. That is a much better message.

[Laughter.]

Just, we do not want our buildings to suck.

Okay.

[Laughter.]

Mr. Allen, you didn't really expound on the Amazon project. Can you describe that a little bit, about how Amazon and the Westin Hotel are sharing in a heat exchange that is driving down the cost by something like four times the need for a HVAC system and how we need to keep going on this innovation?

Mr. ALLEN. Yeah, thank you.

Yeah, I'd be glad to and I'd first like to say, Senator Murkowski, we learned as much about how to help small cities from them than they did about us. So it's more about exploration and ideas, innovation, so that's the thing.

The NAIOP folks, we're members of, is a real estate, commercial real estate organization and they are getting religion. They fought it.

Real estate developers and building owners fought this for a long time and then they finally figured out that two things were happening that the sophistication of the mechanical electrical systems and how occupants occupy a building and some of the demands of the changing office and hospitals and data centers were causing their utility costs to go up. They figured out that they maybe should take a look at energy efficiency as a source to fund, to get more efficient and fund other things with their savings.

The Amazon ECO district was interesting and I want to remind everyone, it's more of—it's small and it's a metaphor for what is possible in a big way around the country. And here's how it started.

The Westin Hotel, the Westin building, next to Westin Hotel, was a telecom building, now a data center building. We managed it. We installed a lot of the equipment there and an engineer on a unicycle that worked for McKinstry met me in the lobby eight years ago and said, welcome to the largest boiler in Seattle. And what he meant was, lots of heat was dissipating from the building from the data centers, lots of rejected hot water was going down the drain. That was a genesis of starting to think about, eight years ago, how do you use that lost energy? So we signed a contract with the building owner in a partnership. We became a utility with lots of regulations and lots of partners and figured out that there was enough wasted heat going into the air and hot water down the drain to provide Amazon's four high-rise towers across the street with all the preheated hot water forever. So, it doesn't sound small; it's small on what is possible.

I think, Senator Cantwell, what you're talking about is there are no bad ideas and that the building stock in America is totally right for all kinds of that idea. Basically, that's a waste to energy and it exists all over the country, in all kinds of campuses, in all kinds of buildings.

Senator CANTWELL. So you're saying we should take these ECO district ideas, or put funding toward a variety of our states and look at what they come back with——

Mr. ALLEN. Right.

Senator CANTWELL. ——as it relates to what might be demonstrations. Just like you said that one——

Mr. ALLEN. Yeah.

Senator CANTWELL. ——came to you as you guys realized where the waste was.

Mr. ALLEN. Yeah, well we're working on one in Spokane. We just announced it yesterday with Avista. So working with a utility and the city and the university district in Spokane, it's going to be a big ECO district where lots of buildings participate in—and I think what the answer is, it needs startup money because unlike, not like—like other industries, that first chunk of money that helps mitigate the risk and get it started helps you build the field that they will come to.

Senator CANTWELL. Thank you.

Thank you, Madam Chair.

The CHAIRMAN. Thank you, Senator Cantwell.

I am going to turn to Senator Capito.

Just for purposes of the Committee's information, we do have a vote that apparently is scheduled at 11:30 this morning. I am going to be popping in and out between different committees, but we will continue this hearing throughout the vote. We will just make sure that we have somebody here watching the gavel, but I want to respect the time of those who have traveled so far. If you have not yet had a chance to ask your question, pop out for the vote and then come on back.

Senator Capito.

Senator CAPITO. Thank you, Madam Chair and Ranking Member and thank the panelists too. Thank you.

Mr. Santa, during the Committee's oversight hearing that we had last week or the week before, we talked about the Polar Vortex and what happened in the Northeast during that very cold part of our weather. It came to light that the ISO New England was having to import LNG sourced from companies in Russia. I asked a question about it, and it is a direct result of a lack of infrastructure necessary to move gas from Marcellus and Utica. I am from West Virginia, so Marcellus and Utica are big plays in West Virginia and in our state. Senator Manchin, obviously, is here as well. So the outcome of this was the higher prices for consumers and buying from foreign sources of energy and also ships passing in the night—American LNG going abroad while we are importing LNG from Russia, Putin's Russia, no less.

You mentioned the Natural Gas Act of 1938 was/is in conflict with this, you mentioned, cooperative federalism. I would like to have you talk a little bit more about that. You mentioned specifically, New York, and obviously in the case of Marcellus and Utica, getting those resources to the Northeastern states is difficult, trying to get through New York, if not impossible. Could you speak to that a little bit more broadly, please?

Mr. SANTA. You're right. It is a remarkable situation. I mean, for example, during the so-called Bomb Cyclone on January 5th, gas for delivery on January 6th, gas priced going into Boston was priced at about $78.80 per million BTUs and yet gas in Leidy, Pennsylvania, the heart of the Marcellus shale and coastal water storage, was priced at $4.20 per MMBTU. And if there are no pipeline constraints, that differential should be a little more than the price of pipeline transportation. So that market is clearly capacity constrained.

While FERC can authorize new pipelines, while pipeline companies are interested in market opportunities, it requires demand on the other side. In particular, customers willing to sign up for pipeline capacity on a long-term basis to finance those projects.

In New England, the wholesale electricity markets are structured in a way that does not provide incentives for generators to contract for that pipeline capacity, nor on the electric side is there the equivalent of the natural gas local distribution company that can aggregate demand and then sign up for capacity based on that.

And so, that's why we have the highly anomalous result that while Marcellus gas is only a couple hundred miles away from New England, imported LNG, and as you know, LNG originating in Russia, is an economically attractive alternative because of that scarcity.

Senator CAPITO. Do you see, in terms of your past experience with FERC, that there is in the national interest, any way to move forward with more infrastructure as we see this supply just——

Mr. SANTA. Well, it's interesting.

In the early days of the Federal Power Commission (FPC), there were a number of instances where the FPC chose to approve pipelines over the objections of states that had a parochial interest in keeping the gas for themselves——

Senator CAPITO. Keeping it in.

Mr. SANTA. ——or for not expanding the market.

The problem we've got now, and we mentioned it in the testimony and Phil Moeller mentioned it as well, is this cooperative federalism issue that the State of New York has utilized its authority under the Clean Water Act to effectively veto FERC's approval of a pipeline. And there, I think, what we need is both clarification from Congress on the scope of state's authorities under the Clean Water Act and certainly respecting their role. And then, also some effective recourse should a state overstep its bounds or act in a way that's contrary to the national interest.

Senator CAPITO. Mr. Moeller, do you have a comment on that?

Mr. MOELLER. I agree with Mr. Santa in that we have challenges. I think we need a focus on all types of infrastructure. Obviously, I'm here representing the electric industry and that's an alternative, but increasingly, the electric industry is using natural gas to generate power. That trend line has been going on for a while and it's increasing. And so these are a set of issues that we look forward to you addressing.

Senator CAPITO. Well, in the last hearing too, we also heard that coal and nuclear have been insufficiently compensated for, particularly during that cold snap when it was so critical to have the baseload capacity, for their baseload generation to the grid. So they slid backward in the dispatch curve.

I am wondering if you believe the market imbalances that fail to adequately compensate coal and nuclear for their important base generation?

Mr. MOELLER. There's an active discussion going on, particularly in the PJM market, about what we call those inflexible units and whether they should be compensated better.

We will see, probably, as part of the RTO responses to the FERC order of January 8th that were due 60 days after being published in the Federal Register, their responses.

I think it's very likely, although it's not a prediction, that PJM will probably raise these issues of inflexible unit compensation in their response. And then, there will be a 30-day period, I think, for people to respond to what the RTOs put in. This will be a lively discussion going forward for the foreseeable future.

Senator CAPITO. Alright, thank you.

Senator BARRASSO [presiding]. Senator Stabenow.

Senator STABENOW. Thank you, Mr. Chairman.

First, this question relates to our mobility sector. Coming from Michigan we are very excited about electrification and autonomous vehicles.

I first want to thank our Chair and Ranking Member for holding a hearing at the Washington, DC, Auto Show a week ago. I appreciate that very much. And we invite everybody to come to the North American Auto Show in Detroit which is the big, big, big one. So we would welcome everybody to come.

But, particularly for Mr. Moeller and Mr. Mezey and Dr. Medlock, and anyone else that would like to respond, I am interested to hear your perspectives on the role of utilities. What role will utilities play in vehicle charging infrastructure?

We heard about that last week. I hear about that everywhere as we try to move this industry forward and whether there are actions the Federal Government can take to accelerate coordination to speed the deployment of electric charging stations which are a major impediment right now for us to move this industry forward.

Mr. MOELLER. Well, thank you, Senator. You've got a great leader and CEO, Patty Poppe from Michigan——

Senator STABENOW. She is great.

Mr. MOELLER. ——who's been part of our effort to expand discussions on expanding EVs.

It's a great question because EVs are coming. Other nations are mandating them. We're seeing a significant market growth of up to seven million of those vehicles on the road by 2025. Charging stations are a key part of that.

They are often—we want the utilities to be able, our energy companies, to be able to deploy them, not to the exclusivity of others, but making sure that our companies can provide that. Sometimes that gets into relatively complicated issues of how those are paid for through the rate structures, but states have been moving forward, I think, quite progressively.

I would contrast what happened in California in 2011, the California Public Utility Commission prohibited our energy companies from actually owning these facilities. They realized that was a mistake and by 2014 reversed that because we need to be in that game. And again, not to the exclusivity of others.

A lot of that's going to play out at the state and local level, and I'll be happy to get back to you on recommendations on federal policy to promote that.

Senator STABENOW. I would appreciate that.

Mr. Mezey?

Mr. MEZEY. Thank you.

I would defer to Mr. Moeller on our utility customers. Of course, we're very excited about the potential of the electrification of the grid and the more efficient utilization of the grid through the electrification of transportation.

What I would say, because this ownership issue is really outside my grade, but what is very important is that the utilities have a role in the siting of these charging stations because improper siting will create tremendous infrastructure costs.

The ability to use the information, the kind of information that we're collecting through our systems, to understand usage patterns, properly site and potentially control when charging is going to occur, will speed the adoption of charging stations because they'll make them more manageable on the electric grid for utilities at a much more economical level.

While the debate may rage on the who owns the asset, certainly encouraging some active participation from the utilities on the proper siting and control of those units within the grid will promote grid stability and adoption rates.

Thank you.

Senator STABENOW. Thank you.

Dr. Medlock?

Dr. MEDLOCK. Yeah, thank you for the question.

You sort of, when you start talking about siting of recharging stations, in a lot of ways in the electric power space, you can open up Pandora's box because it was mentioned the need to have utilities being coordinated in the effort with regard to siting.

But, you know, I draw your attention to the way gasoline stations are currently sited around the country. This is actually done in such a way to reduce consumer's cost associated with driving from Point A to Point B.

So how many of you, when you get in your car, think about where the gasoline station is, unless you're near E? Right? You don't. You just go out and you say I need to go fill up, and do it.

Well, in the current infrastructure environment, you actually have to know exactly where those recharging stations are if you have an EV. So that presents a challenge.

Of course, as EVs begin to grow we're going to have to see more siting and more fungibility with regard to the ability to refuel these electric cars. Of course, that then begs the question, how you get power to those stations? This is where, I think, utilities play a critical role, particularly in areas where you've got competition having been introduced and utilities are not actually owners of generation assets, but they do actually own wires.

And so, you've got to think about coordinating with utilities and coordinating with Departments of Transportation. It becomes a very big issue. It's not an unsolvable issue, but it's one that, I think, has to be recognized, certainly in the world that we're, sort of, moving toward today.

Senator STABENOW. Right, thank you.

Anyone else?

Mr. DI STASIO. Senator, may I?

Senator STABENOW. Yes, Mr. Di Stasio?

Mr. DI STASIO. On behalf of utilities that I work with and also my own experience from California with electrification, some of the things that are current barriers really don't so much relate to charging.

Most charging is done at home and a lot of it's done in the workplace and the residual charging, really, is on corridors that may not have adequate electrical infrastructure.

So some of the discussions and some of the opportunities are starting to look at this as complementary infrastructure where we could put charging at airports. We could put charging at other transportation modal centers.

There is an opportunity to change the paradigm. I would agree with Phil that utility's charging infrastructure is a natural extension of our infrastructure and it's a beneficial end use of electricity that can actually help regulate other intermittent resources on the grid at different times.

The other thing I would say is that, and it's not a federal role, necessarily, but standardization of the infrastructure so consumers don't have different charging infrastructure that creates barriers to widespread adoption.

Then the last thing is, we're probably the only industry that charges our commodity on the metric system, so people don't always understand the value proposition. Creating transparency of what am I paying for, how much of it is the infrastructure, how much is the commodity, will allow people to make an informed comparison to how much am I paying for this versus gasoline?

I do know the automakers are working diligently to offer several new models with longer range. Most every automaker now is going to have some electric options. And so, I do think that consumer adoption is going to happen, and I think utilities are well-suited to help inform how to make that transition a good one.

Senator STABENOW. Thank you very much.

Senator BARRASSO. Thank you, Senator Stabenow.

Mr. Moeller, in your testimony you highlight several factors that create uncertainty in transmission infrastructure development. Specifically, one of those factors is permitting and siting delays which can delay projects, as we know, for more than a decade. Now, I agree Congress should act to streamline and improve the processes of excessive unnecessary delays. They threaten security, jobs, economic growth, all of it.

What improvements should Congress make to the transmission permitting and siting process that would actually advance energy infrastructure in a responsible way?

Mr. MOELLER. Well, thank you, Senator.

A lot of those have been put in, those policies have been proposed by bills both here in the Senate and in the House, but essentially it comes down to the resource agencies being accountable with reasonable timelines and some kind of an appeal process if the decisions are such that they need to be appealed.

Vegetation management is a huge part of this. There are liabilities incurred and yet, many times, energy companies aren't allowed to clear out dead, decaying and potentially threatening vegetation that can have major impacts if left undealt with.

So it's a variety of areas. We're happy to provide you with more perspective on more language, but the ideas are out there. It is a serious set of issues and we've seen it play out, particularly in a number of areas, California notably, over the last——

Senator BARRASSO. Mr. Di Stasio, anything that you would like to add to that?

Mr. DI STASIO. The only thing I would say is that some of the reasons that these things take a long time is that the agencies don't always work in a concurrent fashion, so you end up with a serial process that anywhere in that process it could get kicked back and you start over. It's very, it's not predictable and it's extended by the virtue of the fact that there isn't a clear outcome that everybody's working concurrently to achieve.

Senator BARRASSO. Mr. Moeller, in 1978 Congress passed the Public Utilities Regulatory Policy Act, PURPA, and it was responding, I believe, to the skyrocketing oil prices that were caused by the '73 oil embargo. The goal was to reduce the use of foreign oil in power generation and foster American energy independence, so to achieve the goal they required all electric utilities to purchase power at inflated prices from renewable energy sources known as, they called them qualifying facilities.

Times have changed since then. Renewable energy now accounts for about 15 percent of electric generation and oil only produces about 1 percent of electricity generation. I am concerned this is an outdated law, and significantly raises cost for consumers. What changes should be made to that law to reflect the realities of the modern energy market?

Mr. MOELLER. Well, thank you, Senator.

The realities are that, particularly as it pertains to renewable generation, we can generate that power at much less, often half, the cost of smaller generating units of the same type of fuel, wind and solar especially. So if we're really talking about promoting those fuels, presumably we'd want to promote them in the least cost possible and that's usually done with larger scale. And PURPA, essentially, favors smaller development.

Legislation will definitely—is something that we support. There's a mandatory purchase obligation which and sometimes is very problematic because we've had, due to the success of energy efficiency and a number of other factors, we have many areas of the country that are either in flat or declining load patterns. And yet, when our energy companies and then our customers behind them have to purchase power they essentially don't need and then you add the cost to it, that's very inefficient and not, essentially, good for the economy or the customers themselves. So the one mile rule, the megawatt thresholds can be addressed by FERC, legislatively. Some of the areas would have to be addressed by Congress.

Senator BARRASSO. One last question for you.

In September of last year, the Mountain West Transmission Group announced their intent to join the Southwest Power Pool (SPP) of the regional energy market.

Mr. MOELLER. Yup.

Senator BARRASSO. And the members of the group include utilities that serve a large portion of my home State of Wyoming. Could you please explain the benefits and the cost savings to Wyoming customers that are going to result from these utilities joining in this regional energy market?

Mr. MOELLER. Absolutely.

It kind of goes back to the original premise of my testimony which is that a larger transmission footprint allows for a more efficient dispatch, access to cheaper electricity depending on the time of day, more resiliency, more reliability. That's the concept behind a larger transmission footprint or power pool.

SPP, obviously, now operates in the Eastern Interconnection. This would be a change to then go to the Western Interconnection.

Some of the things that people always focus on when they're looking at joining a market are the governing structure, making sure that there are cost benefits to all the members. Our existing members want to make sure that they're not paying more with the expansion, but SPP has assured them that they won't.

There will be some challenges, especially with the two interconnects involved, but overall, the concept of a larger transmission footprint typically increases the resiliency and the reliability of the system and provides access to lower cost generation.

Senator BARRASSO. Thank you.

Senator Cortez Masto.

Senator CORTEZ MASTO. Thank you.

Thank you, first of all, for the important discussion today.

Gentlemen, welcome.

I was heartened to hear the conversation, your testimonies, because it is right up my alley. In Nevada, we are very excited about the use of this new technology in so many different forms and fashions. One of the areas that I am working in is the smart communities and the use of the smart technology and the interconnectivity of things.

Along with one of my Republican colleagues, I introduced the Moving FIRST Act. And really, it incentivizes communities to start thinking about how they can collaborate and work on smart communities, and it reinstates the Department of Transportation's Smart City Challenges, if you are familiar with that, to create more opportunities for communities of all sizes to work together and address individual needs there when it comes to transportation and the use of technology.

That includes what we have talked about a little bit today, is the expansion of the electric vehicles, which is a fundamental element to the kind of application, I hope, that the grand challenge will address to increase energy efficiency and reduce the transportation sector's carbon footprint. It sounds like this concept is something that I hear that you would all be supportive of, is that correct?

Just a yes is fine, if you want to go down——

Mr. MOELLER. Yes.

Mr. MEZEY. Absolutely, yes.

Mr. DI STASIO. Yes.

[Laughter.]

Senator CORTEZ MASTO. Okay, so let me put it this way, does anybody disagree with that comment?

[Laughter.]

Alright, so it's a unanimous yes.

Let me ask this, Mr. Moeller and Mr. Di Stasio. With that concept in mind, are you able to be flexible enough to work with local jurisdictions to help them improve their transportation or energy sectors with support from the Federal Government?

Mr. MOELLER. Well, absolutely, thank you, Senator, for bringing this up.

We think that the electric grid is really the backbone, the foundation of the smart community movement and can enable a lot of things, and John can talk about it a lot from his SMUD experience, but the smart meters and the smartgrid have a lot of capacity that presently isn't fully utilized and from a telecommunications and information-sharing network perspective, it's a great platform for a lot of the other issues to come about.

We do have some issues coming on with the 5G network and such——

Senator CORTEZ MASTO. Right.

Mr. MOELLER. ——that deal with the FCC and pole attachments that we ought to address later on, but I don't want to get us off topic.

Senator CORTEZ MASTO. Thank you, that is something that needs to be considered as well. I appreciate your comments.

Mr. DI STASIO. I, too, would say that there are great opportunities. I mean, we have really moved. Smart meters probably created the platform to create transparency and interoperability and now we're able to move down the pipe to start to look at the concept around the Internet of Things, but the great opportunity is efficiency of consolidations. So municipal entities can now start to have, instead of having several disparate networks or several different processes that, kind of, operate independently, all of a sudden the community or even a region can start to have a platform on which there are a lot of interoperability.

Clearly, we have to still have good attention to cyber. These are physical assets that have a digital network over them. But the reality is, there really are a lot of opportunities supported by technology and smart communities. When you say, is it good for local jurisdictions, many of our members, as public power, are local jurisdictions. So it's good that they have the decision-making there to be able to do things to advance a variety of community or city interests.

Senator CORTEZ MASTO. Okay, thank you.

Another area I just want to focus on, I don't have much time, is battery technology. In Nevada, we are home to a large battery factory, the Tesla Gigafactory. And Nevada recently created its Renewable Energy Bill of Rights that protects home energy generation and storage. Thanks to declining costs, better technology and a growing industry, battery storage deployment at a utility scale is accelerating at a rapid pace.

Let me just open this up and maybe we start, Mr. Moeller, with you and again, Mr. Di Stasio, but anybody if you want to weigh in.

What are the barriers? And what can we do, the government, to help address those barriers as we look to battery storage deployment and the future benefits?

Mr. MOELLER. Thank you very much, Senator.

The challenge with batteries and storage is, number one, you have to make sure you're clear with whoever you're talking about on the definitions because storage can mean about 20 different things based on the technology and whether it's in the wholesale market or the retail market, but FERC can deal with it in various ways. A lot of state commissions are dealing with it in their ways.

The rapid improvement and the reduction of costs is very promising for storage. I think as it is deployed, particularly the distribution level, we want to make sure that there aren't cost shifts so that people who don't have access, maybe don't have the wealth to afford such a system, are not having their costs covered by people who don't.

So a lot of it goes back to the rather arcane but important area of state rate structure and how they treat these technologies.

Senator CORTEZ MASTO. Thank you.

Anyone else?

Mr. ALLEN. Yeah, I'm the past Chair of the State of Washington's Clean Tech Alliance which has 280 members from every facet of efficiency, to utilities, to innovation, to labs. And Washington State is home to two or three of the big innovation breakthroughs on battery. From what I hear from them is, notwithstanding what you just said about the differences, that I would think that the Federal Government would think that would be a good bet to help fund the acceleration of battery storage as it applies to global competitiveness because a lot of people that we work with think that is the big grail to the next efficiency revolution, the transition revolution.

Senator CORTEZ MASTO. Thank you.

Mr. DI STASIO. The only other thing I would add is, as Phil said, storage can take many forms and there is a role for the Federal

Government to make sure that we can advance battery technologies so that we get the best economic and environmental performance.

The reality is the costs have come down a lot. Scale matters, even in batteries and where they're deployed. So understanding how to advance these technologies to get them to the best state they can be in, I think, still is an opportunity for whether it's R&D funding or support by DOE, there's still opportunities to advance those technologies.

Senator CORTEZ MASTO. Great. Thank you.

Dr. MEDLOCK. I have one thing, yes. Fascinating conversation.

First thing I'll say is efficiency is a virtual source of supply. So everybody should just recognize that. And I sort of address that to you, Senator Cantwell, based on the statement you made about "make our buildings not suck."

[Laughter.]

If we all recognize efficiency is a virtual source of supply, it changes the calculus when we're discussing investments in infrastructure as we go forward.

On storage, the role the Federal Government can play, I think, primarily right now, is in basic R&D. That's really where funding from the Federal Government can play a tremendous role in potentially accelerating technologies that occur, pre-infancy or in infancy at the current moment.

But beyond that when you start talking about implementation of storage you can, sort of, draw some parallels to the natural gas industry. I forget the FERC order, but storage in the natural gas grid was actually made so that rates were market-based a little over a decade ago, I guess, maybe a little bit longer now. But what that did is it triggered a landslide of investment in storage facilities to increase the turn rates of the—so how fast I can go in and out because it actually made the ability to apply a new technology monetizable.

That's something that market structure plays a critical role to and it's something I mentioned in my written testimony and alluded to it in my statement. But that's something that you should all, hopefully, keep in mind is the role that pricing plays in facilitating innovation.

Senator CORTEZ MASTO. Thank you. Thank you very much.

Senator BARRASSO. Senator Daines.

Senator DAINES. Thank you, Acting Chairman Barrasso, Chair Murkowski, Ranking Member Cantwell, for holding this hearing, a timely hearing given the infrastructure seems to be on the top of many minds lately, not the least of which is our President's infrastructure. And that doesn't just mean roads and bridges. It also includes broadband, national parks and, important for today and really important for Montana, energy infrastructure.

I just returned from visiting nine counties on Friday and Saturday last week in Montana, in Eastern Montana. Some of these places, as they say, it's not the in of the Internet, but you can see it from there. This is out, off the beaten path, extreme Southeast Montana, the salt of the earth Montanans live there.

The Keystone pipeline, for example, would be one of the pieces of infrastructure that will go through some of those counties, natural gas liquids pipelines, CO_2 pipeline, near Baker, Montana and Fallon County.

In fact, a little side story. I was in Ekalaka which is in Carter County, extreme Southeast Montana, with a graduating class of seven students. Welcome to Eastern Montana. These are kids that, oftentimes, are growing up on ranches in the area. I asked the Superintendent, I said, where are we getting the money to fund their schools? They just built a new gymnasium. They have a lot of their regional Class C basketball tournaments there. It is the pride. He said 94 percent of the revenues that come to our school to support education, teachers, infrastructure, come from pipeline revenues. I tell you what, it is the lifeblood for our infrastructure to support our schools in places like Eastern Montana.

We have come a long ways on pipeline safety. I am happy to have helped author the Safe Pipes Act which was signed into law in 2016 which will make the transportation of oil and natural gas even safer. All are critical to moving energy that will fuel our nation and, importantly, fuel the entire world.

As the state, Montana, with the largest deposit of recoverable coal in the nation—now when you think of Montana, most of the time we think about fly fishing and rivers and the beauty of our state which is absolutely true, and I love to do those things. We also have more coal, recoverable coal, than anybody else in the nation. We are looking for approval of coal export terminals so we can begin moving our coal through domestic ports, creating American jobs, rather than having to go north and then west through Canada.

Security and reliability of our electric grids, also top of my mind, especially when they work to protect reliable baseload power that comes from the Colstrip Power Plant, especially in summer when we have the wildfires. We had a horrible wildfire season out West. Montana had one of our toughest seasons in a long time.

These fires are raging across our national forests and they become difficult to manage and they sometimes pose risk, of course, to utility lines. We had that situation in one of the counties. I called one of our sheriffs up in one of our counties in Southwest Montana, where we had one of our large fires. He said, “Steve, we are battling a fire and are trying to protect a 500 kV transmission line that’s running from Colstrip out west.” But because of restrictions and regulations on commonsense vegetation management, it has put these lines at risk. However, when the fire was burning they couldn’t move their fire crews in there to try to protect the transmission line because the carbon particles were in the air from the fire and they were in fear of arcing coming off those high voltage lines could kill a firefighter.

So here we are, we are literally between a rock and a hard place. It is why I am going to talk about that here at the end, why we need to get some changes made here to how we can more effectively manage and protect infrastructure.

In Montana, we house minerals that are building blocks of a lot of infrastructure: sand, gravel, world-class copper, palladium, silver. We need to be sure we can access these materials domestically and not have to rely on nations overseas.

I hope bills emerge from this Committee and others that strengthen all of our energy assets for more expeditious approval of pipelines, export terminals, to protect baseload terminal or power, as well as helping federal land managers be better partners with power companies, back to vegetation management and allowing us to recover our own raw materials.

My question for Mr. Moeller. Can you explain to this Committee how critical it is that Congress address the issue now that arise from vegetation management in and adjacent to electric rights-of-way? I am very disappointed that we did not get a wildfire funding and forest management reform package as part of this budget caps deal. We got very, very close, once again. It's kind of like Lucy and the football right now. Right in the last minute it was grabbed from us, but I am not giving up.

Tell us why streamlining regulatory reviews between the agency and power companies and also providing some certainty and relief in the liability piece is important.

Mr. MOELLER. Well, thank you for the question, Senator.

I think all you have to do is look at calendar year 2017 and the extent of wildfires throughout the country. This has been an issue for a while. I remember ten years ago working with some folks in Colorado because of the pine beetle issue that I know Senator Gardner is well aware of, where if there's a threat to millions of people's ability to enjoy the delivery of resilient, affordable, reliable power when these power lines can potentially be put out because of a wildfire. And we've had devastation in the West. You mentioned Montana, other states, California, as well.

So I would certainly lend our voices to the sense of urgency to deal with vegetation management.

Senator DAINES. Thank you.

Senator BARRASSO. Senator King.

Senator KING. Thank you.

Before beginning my question, I have to put into the record, with all due respect to my esteemed colleague, the distinguished Senator from Wyoming, that is what you say around here before you put the knife in.

[Laughter.]

PURPA plants do not pay inflated prices. The price is called "avoided cost," and it is what the utility would have otherwise had to spend to generate the next marginal kilowatt-hour.

So that is a bit of mythology that has been out there for years, and I am tired of hearing it because I was in that business. I know what avoided cost is. And the idea that, and Mr. Moeller this goes for you too, the idea that these plants are paid inflated prices is simply not true.

So let me move on.

One funny note, Mr. Mezey, you talked about finding—can't find a gas station. I have an app. I have an electric car and I can press the app and find that there are 73 charging stations within the District of Columbia. So we are getting there.

Here is my question. And Mr. Allen, I think you hit it. I know from my experience, I have been in the generation business and the conservation business, it costs about half as much to save a kilowatt-hour as it does to generate one, so economically, conservation makes an enormous amount of sense.

The problem I see with the grid, and that is what we are talking about here, is that it is wildly inefficient. It is like a church that is built for Christmas and Easter and has a lot of empty pews the rest of the year, because we have to build to the hottest day, the highest demand of the year. The rest of the time the grid is grossly underutilized.

To me the challenge is, how do we incent users of electricity to make more efficient use of the grid? And it seems to me, things like time-of-day pricing makes sense.

I remember the day when on telephones you looked at your watch and when it became one minute after nine, you made a phone call because it cost half as much after nine as it did before. Isn't this one of the directions that we have to move in?

Mr. ALLEN. Yes, in fact, I'm on the Citizens Review Panel for Seattle City Light which is a, you know, fairly clean utility using hydro. We're in to about two-thirds through advanced metering and, as you can imagine in Seattle, there are thousands of electric cars and they're dealing with a conundrum of——

Senator KING. But if they are charged at night, that helps everybody.

Mr. ALLEN. Yeah, well that's—we're going to go to demand pricing on electricity, for sure.

Senator KING. And that will lead to greater efficiency of the grid——

Mr. ALLEN. Right.

Senator KING. ——and therefore, not having to build additional.

Mr. ALLEN. Yeah, yeah, the whole transparency of the grid is where we're going. So, a two-way conversation between the consumer and utility, you'd be able to see where the prices are, when the load is and people will learn that.

Senator KING. Mr. Moeller, I was surprised in your testimony, you said 11 percent. I looked for that chart in the Energy Review, Table A8, 2017. I couldn't find it. Perhaps you can send it to me.

Mr. MOELLER. Yes, I've got it saved.

[The information referred to follows:]

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case 2015	2016	2025	2030	2035	2040	2050	Annual growth 2016-2050 (percent)
Net generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1,323	1,197	1,172	992	950	915	852	-1.0%
Petroleum	24	19	11	9	8	7	6	-3.5%
Natural gas[3]	1,110	1,169	1,012	1,208	1,350	1,473	1,738	1.2%
Nuclear power	797	798	773	768	721	702	608	-0.8%
Pumped storage/other[4]	2	3	3	3	3	3	3	0.1%
Renewable sources[5]	507	554	933	987	1,045	1,134	1,317	2.6%
Distributed generation (natural gas)	0	0	0	0	1	2	4	- -
Total	**3,764**	**3,740**	**3,906**	**3,967**	**4,079**	**4,236**	**4,529**	**0.6%**
Combined heat and power[6]								
Coal	17	22	20	20	20	20	20	-0.3%
Petroleum	2	1	1	1	1	1	1	0.0%
Natural gas	131	144	139	139	139	139	137	-0.2%
Renewable sources	4	5	5	5	5	5	5	0.0%
Total	**158**	**171**	**165**	**165**	**164**	**164**	**162**	**-0.2%**
Total net electric power sector generation	**3,921**	**3,911**	**4,071**	**4,132**	**4,243**	**4,400**	**4,691**	**0.5%**
Less direct use	17	21	20	20	20	20	20	-0.1%
Net available to the grid	**3,904**	**3,890**	**4,050**	**4,112**	**4,223**	**4,380**	**4,670**	**0.5%**
End-use sector[7]								
Coal	14	14	13	12	11	11	10	-1.1%
Petroleum	1	1	1	1	1	1	1	-1.2%
Natural gas	100	102	130	151	176	205	271	2.9%
Other gaseous fuels[8]	11	11	21	20	20	20	21	1.8%
Renewable sources[9]	49	53	93	122	163	215	366	5.8%
Other[10]	3	3	3	3	3	3	3	0.0%
Total end-use sector net generation	**178**	**185**	**260**	**310**	**375**	**456**	**671**	**3.9%**
Less direct use	129	135	213	257	316	387	567	4.3%
Total sales to the grid	**50**	**50**	**47**	**52**	**59**	**69**	**105**	**2.2%**
Total net electricity generation by fuel								
Coal	1,354	1,233	1,205	1,024	981	946	882	-1.0%
Petroleum	28	21	13	10	10	9	7	-3.1%
Natural gas	1,341	1,414	1,282	1,499	1,666	1,818	2,150	1.2%
Nuclear power	797	798	773	768	721	702	608	-0.8%
Renewable sources[5,9]	560	612	1,031	1,114	1,213	1,354	1,687	3.0%
Other[11]	20	17	27	27	26	27	27	1.3%
Total net electricity generation	**4,100**	**4,096**	**4,331**	**4,442**	**4,618**	**4,856**	**5,362**	**0.8%**
Net generation to the grid	**3,954**	**3,940**	**4,097**	**4,164**	**4,282**	**4,449**	**4,775**	**0.6%**
Net imports	**66**	**57**	**57**	**50**	**45**	**42**	**41**	**-0.9%**
Electricity sales by sector								
Residential	1,400	1,410	1,383	1,402	1,436	1,479	1,521	0.2%
Commercial	1,358	1,360	1,354	1,372	1,407	1,463	1,622	0.5%
Industrial	959	946	1,113	1,107	1,126	1,162	1,236	0.8%
Transportation	9	11	42	65	83	98	120	7.4%
Total	**3,726**	**3,727**	**3,892**	**3,947**	**4,052**	**4,202**	**4,499**	**0.6%**
Direct use	146	156	233	278	336	407	587	4.0%
Total electricity use	**3,872**	**3,882**	**4,125**	**4,225**	**4,388**	**4,609**	**5,086**	**0.8%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2016-2050 (percent)
	2015	2016	2025	2030	2035	2040	2050	
End-use prices								
(2016 cents per kilowatthour)								
Residential	12.8	12.4	13.7	13.9	13.9	13.9	14.4	0.4%
Commercial	10.8	10.4	11.5	11.7	11.6	11.5	11.6	0.3%
Industrial	7.0	6.9	7.5	7.8	7.7	7.8	8.0	0.4%
Transportation	10.4	10.1	13.4	13.8	13.5	13.4	13.3	0.8%
All sectors average	**10.6**	**10.3**	**11.2**	**11.4**	**11.4**	**11.4**	**11.6**	**0.4%**
(nominal cents per kilowatthour)								
Residential	12.7	12.4	16.6	18.8	20.7	22.8	29.1	2.5%
Commercial	10.6	10.4	13.9	15.8	17.3	18.9	23.5	2.4%
Industrial	6.9	6.9	9.1	10.5	11.6	12.7	16.1	2.5%
Transportation	10.3	10.1	16.3	18.6	20.2	22.0	26.9	2.9%
All sectors average	**10.4**	**10.3**	**13.5**	**15.4**	**17.0**	**18.6**	**23.5**	**2.5%**
Prices by service category								
(2016 cents per kilowatthour)								
Generation	6.5	5.9	6.6	7.1	6.9	6.8	7.2	0.6%
Transmission	1.1	1.1	1.3	1.3	1.4	1.4	1.4	0.6%
Distribution	2.9	3.3	3.3	3.1	3.2	3.2	3.2	-0.1%
(nominal cents per kilowatthour)								
Generation	6.4	5.9	7.9	9.6	10.3	11.2	14.6	2.7%
Transmission	1.1	1.1	1.6	1.8	2.0	2.3	2.9	2.8%
Distribution	2.9	3.3	4.0	4.2	4.7	5.3	6.4	2.0%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	2.19	1.10	1.11	0.93	0.95	0.93	0.88	-0.7%
Nitrogen oxide (million short tons)	1.35	1.01	0.96	0.88	0.84	0.82	0.80	-0.7%
Mercury (short tons)	23.46	4.90	4.72	3.97	3.77	3.59	3.31	-1.1%

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes plants that only produce electricity and that have a regulatory status.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2016 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2015 are model results and may differ from official EIA data reports.
Sources: 2015 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, October 2016, and supporting databases. 2015 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2015 electricity prices by service category: EIA, AEO2017 National Energy Modeling System run ref2017.d120816a. 2016: EIA, *Short-Term Energy Outlook*, October 2016 and EIA, AEO2017 National Energy Modeling System run ref2017.d120816a. **Projections**: EIA, AEO2017 National Energy Modeling System run ref2017.d120816a.

Senator KING. In New England, transmission and distribution is 50 percent of our bill. In fact, it is more than the cost of energy today. So what am I missing?

Mr. MOELLER. I was focusing solely on the transmission side of the bill, not the distribution side.

Senator KING. Okay, so you didn't include distribution.

Mr. MOELLER. Correct.

Senator KING. So isn't it true that transmission/distribution is now roughly 50 percent of the bill?

Mr. MOELLER. I don't want to commit to that without checking the numbers, but it depends on the region.

Senator KING. Yes.

Mr. MOELLER. I mean even places—my ranch in Washington State, I probably pay closer to 11 percent for transmission, but here, living here, it's much less than that.

Senator KING. And isn't one of the problems—Mr. Allen, I will ask you this question—that our whole rate structure is built, is based upon an incentive to build?

Mr. ALLEN. That's right.

Senator KING. If you get paid by a rate of return on your capital investment, that is—and I am not, this is not a criticism, it is just an economic fact of life—doesn't that encourage building rather than, for example, conserving?

Mr. ALLEN. Yes, it does. And also, we've built a system where the goal is to deliver it cheap. So, if you're, like in Washington, we've had real, really cheap power for 50 years and the result of that is you had a lot of people that just—it didn't even come on their family budget income——

Senator KING. Right.

Mr. ALLEN. ——in their thinking about their bill.

So, yeah, I think there's—and these guys——

Senator KING. We need a different model that will compensate the utilities sufficiently——

Mr. ALLEN. Yeah.

Senator KING. ——and fairly, but not necessarily have an inherent incentive to build.

Final question and I will take this for the record.

I would like to ask Mr. Moeller and any of you others, particularly, I am very concerned about the issue of permitting costs and time and delay. I would like from you specific suggestions about what we could do that does not compromise environmental standards but simply reflects greater efficiency in the process and timeliness.

For example, I think you mentioned, Mr. Medlock, the serial nature of permitting. In Maine, we did one-stop permitting and we did not lower the standards, but we improved the efficiency of the process. I am looking for suggestions along those lines. I am very sympathetic to that issue, but I do not want to compromise environmental standards.

Mr. MOELLER. Nor do we.

We'll get that to you, Senator.

Senator KING. Thank you.

Thank you, Mr. Chairman.

Senator BARRASSO. Senator Hoeven.

Senator HOEVEN. Thank you, Mr. Chairman.

What I would like to ask each of you is give me your one or two best ideas on how we are going to build more energy infrastructure, whether you are a fan of traditional energy, fossil fuels, coal, oil, gas, you name it, or renewables. We need to build transmission, we need to build pipelines and we need to build transmission lines for electricity. That is a huge challenge now, the permitting, the siting and all the approvals. How do we work together, traditional energy advocates, renewable energy advocates, to build this transmission that our country needs? And I would like to hear your one or best two ideas how we are going to accomplish that.

Mr. Moeller, maybe you could start?

Mr. MOELLER. As you alluded to, I think, accountability in the permitting phase is, kind of, lacking right now and that can be upped as well as increasing the investment in certain—the climate of increasing the certainty in the investment situation because these, as I mentioned, are multidecade assets that often——

Senator HOEVEN. Specifically, how do we address accountability and certainty? What policy measures do that?

Mr. MOELLER. Through legislative direction to the resource agencies where there's a timeline involved, we can come up with other creative ways to make sure that if there's a decision that is against something, that there's an adequate way to appeal that decision, perhaps to the head of the agency in a timely manner.

Senator HOEVEN. So timeline and some kind of appellate process?

Mr. MOELLER. Correct.

Senator HOEVEN. Okay, good.

Mr. DI STASIO. The thing I would say is recognizing there's regional differences and even structural differences amongst energy providers.

If the Congress can get clear around what are the national priorities in terms of outcome policies, whether that's a focus on resilience, whether it's a focus on innovation, on the economy and, kind of, unleash the creativity that's resident amongst all the different states while respecting these regional differences.

I think one of the things we've suffered from is solutions rather than outcomes because we actually do have a lot of brain power. We can achieve many things, but if certain things are prescribed as silver bullets, they end up becoming difficult to manage.

In my own experience, I think, we are, we stand ready to build things that the one thing that we have in public power that probably, maybe not within the jurisdiction of this Committee, but we're not always, because we're non-taxpaying entities, we don't always have access to incentives that are provided through the tax code.

And so, then we end up having to find a taxpaying counterparty to do a wind project or something. And it really siphons off some of the benefit that would otherwise go to building more infrastructure and providing benefits to the communities.

Senator HOEVEN. Okay.

Mr. ALLEN. Yeah, in our, in the Pacific Northwest, we have an interesting observation. This is definitely not in my network, but an interesting observation is we've almost doubled the square foot-age of facilities in King County and particularly in the city of Seattle and it's a no-growth utility.

So, as, and you talk about working it together, as the utilities worked with consumers and businesses to be more efficient and they grew. They had less consumption per square foot that now we have twice the infrastructure and the same size utility. I'm not saying that can happen everywhere. New York is working on that. New York City is working on that.

But, yeah, you mentioned working together. I think, in general, that's where you're getting at too and it's going to take a whole community effort to, kind of, balance all these disparaging views to get some common sense on the effectiveness and efficiency.

Dr. MEDLOCK. Thank you for the question.

I think it's very important to recognize the interdependence of infrastructures. The comment was made by Senator King, unfortunately he had to leave, about build to peak. So the idea that we over-scale capacity—

Well, that occurs in a situation where you have limited demand response at the end of the line and you have no ability to store. We've talked about both of those issues today in a lot of detail. I think addressing those things actually begins to address things that are farther upstream, so the transmission and distribution discussions that we're having as well. So all these things are interrelated and they need to be addressed in such a way that we recognize that.

The other thing and this——

Senator HOEVEN. Do you mandate that or do you incentivize that?

Dr. MEDLOCK. I think you incentivize it.

Senator HOEVEN. Okay.

Dr. MEDLOCK. Absolutely.

The other thing to be recognized, and this is an example of a failure by policy to recognize the interrelated nature of infrastructures, there were policies put in place in the State of Texas which I referred to that incentivize the expansion of wind capacity. Well, all of that occurred and then all of a sudden regulators and power retailers and distributors all of a sudden realized we can't get that power to market.

Senator HOEVEN. Right. You have a real challenge between baseload and peak.

Dr. MEDLOCK. Exactly.

And so, all of a sudden, it required the state to step in and create renewable energy zones. This was a State of Texas issue, obviously, and the construction, or another expensive $7 billion to expand transmission.

One could argue that if all of that had been done up front in a coordinated way, it would have been a much more efficient——

Senator HOEVEN. But a huge issue, because it goes, again, to baseload, intermittent. Who built the power? Who has priority to the transmission line?

Dr. MEDLOCK. Well, there's a host of issues.

Senator HOEVEN. Huge issues, not just in Texas.

Dr. MEDLOCK. No, absolutely. There's a host of issues related to what's been going on in the power grid.

Senator HOEVEN. Very important issue.

Dr. MEDLOCK. Absolutely.

Senator HOEVEN. No, I think you really have some good things you have touched on there, very important.

Yes, sir?

Mr. SANTA. Yeah, Dr. Medlock talked about the importance of price signals and the ability to respond to them. I think we largely have that in the case of natural gas pipelines.

Mr. Moeller talked about the permitting process and accountability. I think the accountability there, the predictability of it, and as he noted the recourse in the event that an unfavorable outcome is reached is very, very important.

And also, it's been mentioned earlier, kind of, eliminating the serial nature of this permitting and getting it happening concurrently. I mean, think about for a pipeline the number of approvals that have to be gotten from different bureaus and offices within the Department of the Interior. Do they coordinate with each other?

Senator HOEVEN. I think these are some good ideas there. I appreciate it.

Senator BARRASSO. Senator Hirono.

Senator HIRONO. Thank you very much. I thank the panelists.

I have a question for Dr. Allen. Yes, you did come a long way, but if you came from Hawaii that would be even longer.

[Laughter.]

Mr. ALLEN. I just spent a month doing—studying the energy efficiency, distributed energy of the island, the Big Island of Hawaii.

Senator HIRONO. Great.

Okay, so you are very familiar that Hawaii has six separate electric grids because we are an island state.

I do appreciate your interest in funding for smartgrid demonstration projects in rural areas and other communities where the central grid has limited reach. We actually don't have a central grid as such.

Last Congress I introduced the Next Generation Electric Systems Act to provide grid demonstration grants and was pleased that the Chair and Ranking Member of this Committee included many of its provisions in the Energy Policy Modernization Act and their Energy and Natural Resources Act this Congress. I wanted to ask you what are the most promising opportunities you see—and I think you cited to some of them, such as in our schools—for grid demonstration projects that could help rural and hard to reach communities with lowering their their energy costs?

Mr. ALLEN. Well, obviously, I think the ECO districts could be a small community. Hawaii has several in process or communities that are sharing agriculture and power and distributed energy from solar.

I think some of the bigger opportunities would be, would probably be in lighting and for street lighting which brings LED, of course, it also brings safety.

And there's all kinds of technologies that are vetted.

We've got work, recovering methane from small cities and turning it into energy.

We've been doing——

Senator HIRONO. Talking about methane from waste?

Mr. ALLEN. Yeah, from waste procedures, yeah.

But yeah, there's just the schools have unending needs because of—we did a project in Minnesota for a school. We did an energy reduction program for a district. After we were done, it delivered 24 percent and we put in dashboards in all the schools so the kids could see the watts per square foot, the water per pupil, all the metrics and they competed with each other to see who could beat those numbers. It lowered the energy another ten percent.

Senator HIRONO. I'm particularly intrigued by what you are doing in the schools because of energy costs in our Department of Education. Hawaii has the only statewide school system in the entire country and energy costs account for a lot——

Mr. ALLEN. A lot, yeah.

Senator HIRONO. ——a lot of that, so perhaps we can get with you to have some specifics, and I would like to find out whether Hawaii schools are embarking on those kinds of projects.

For the entire panel, the Department of Energy has been a key supporter of Hawaii's efforts to transition from importing oil. We were the most oil-dependent state in the entire country to renewable energy, including a goal of 100 percent renewable electricity by 2045.

Last week the Washington Post reported the White House is considering cutting the budget for the Department of Energy's Renewable Energy and Energy Efficiency Office by 72 percent—that is, like, eliminating the Office—from current levels.

Can you comment on the importance of public investment in renewable energy and energy efficiency technology provided by the U.S. DOE and what impacts would be of the major funding cuts to DOE on the pace of clean energy technology innovation? I believe Mr. Di Stasio and Dr. Medlock mentioned the importance of the federal role in R&D. Would you like to comment on what a 72 percent cut would mean to this Office?

Mr. DI STASIO. Again, I think it's important that a lot of these, a lot of the help that industry needs, at least utilities need, is not direct funding support. It's really more in the R&D space, helping commercialize things that would be too risky to invest in directly.

So to the extent there's support from the Federal Government through DOE, I know we benefited significantly from the smartgrid investment grants that were issued some years ago, as did many of our members. And those provide very, very good learnings to make risk-free investments going forward.

Senator HIRONO. So I take it that this kind of a cut would not be a good idea.

Mr. DI STASIO. Well, again, I would stop short of—Congress and the Administration will make a determination with the budgets. All I can say is these have been valuable and important functions in the past.

Senator HIRONO. Would the rest of the panelists agree?

Mr. MEZEY. One other point I would make about the role of DOE is, as an advocate for efficiency and renewables, the establishment of a common set of standards and the convening power of the group in order to bring industry together has, beyond a funding source, has a snowballing effect on helping to drive innovation through standards and clarity and communication. And I would say that DOE has played a very positive role in our portion of the industry.

Senator HIRONO. And should continue to play such a role. Would all of you agree?

Dr. MEDLOCK. I would argue that the central role for the DOE with regard to energy efficiency and the Office, in particular you're arguing about, is one, to provide funding for R&D.

Senator HIRONO. Yes.

Dr. MEDLOCK. Not necessarily implementation or deployment because R&D will ultimately lead to discoveries and innovations that the market itself will incentivize the deployment of.

So when we think about or put that lens on it, I think, the discussion really should center on the ability for DOE to fund R&D successfully.

Senator HIRONO. Would you agree that R&D funding is a major role for the Federal Government, U.S. DOE——

Mr. DI STASIO. Well, I would say for sure, I would think——

Senator HIRONO. You can just nod. I am running out of time.

Mr. DI STASIO. I think, probably, a third of everything we've done in these, especially smaller communities, in the builds environment, have come from trying things that needed vetting, that needed trying. Even in your great state, I noticed ocean thermal energy is being researched. I saw a thing on waves. Those things don't happen without R&D and they can't come to life unless you vet it and try it. And we have done a bunch of things that failed, shockingly, but we tried.

Senator HIRONO. Yes, and another thing that happens that encourages the private sector to come forward is to set certain standards. When you set a standard of 100 percent of renewable for electricity, then people come forward and tell us that here is how they can help the state do that. That is why I have been supporting a national energy efficiency standard, for example.

Thank you very much.

The CHAIRMAN [presiding]. Thank you, Senator Hirono.

I think we do recognize that, again, in many of these far-flung places where there are very high costs, it can be a great opportunity to be the demonstration, to be the pilot, because if you can make these technologies pencil out in a high-cost environment, they are going to be okay elsewhere.

So we encourage that and understand, I certainly understand, the role that DOE plays within the R&D and how we can really use these as the incubators of good ideas, but you have to have a place to test them. And you do fail. I know it is tough for some people to realize that, but sometimes that failure actually allows us to succeed on the next time around instead of just shutting it down and saying no, we couldn't. So enough of that.

I want to direct this question to you, Dr. Medlock. We had a really interesting hearing about a month ago here in the Committee. We had Dr. Birol, who is the Executive Director of the International Energy Agency, and he presented the 2017—oh, it must have been the 2018 World Energy Outlook. One of the things that he started with, he had four upheavals. The first upheaval was the fact that the U.S. is becoming the undisputed global oil and gas leader. That is exciting, certainly exciting for a state like mine that is an oil and gas producer and contributor. But it, kind of, begs the question. It is one thing to have the resource and it is another thing to be able to move the resource, whether it is the wind in Texas or whether it is the oil on the North Slope, you have to have the infrastructure.

The question to you is, given your understanding of the energy markets, the critical role of transportation and trade in these markets, are we ready for this? Are we prepared for the growth in oil and gas production and LNG exports given the infrastructure that we have and knowing of the need to move it to those areas where it can provide the country with the greatest value?

Dr. MEDLOCK. There is a lot of infrastructure investment that is still needed to connect those supplies to viable markets.

We published a study back in 2015 when the discussion about the export ban was raging, and one of the things we pointed out is that lifting the ban would unlock a tremendous amount of pent-up capital aimed at not only developing resource but allowing it access to markets that it never had access to before.

And you're actually seeing that occur in the State of Texas, for example, connecting the Permian Basin to the Gulf Coast is occurring increasingly every day, expansion of port facilities, development of pipeline facilities, development of petrochemical plants that have access to those export outlets. All sorts of things are going on.

So that needs to continue to occur if the wealth of the United States is to continue to grow in the energy space. I mean, you go back 15 years, and who would have dreamed that we'd be talking about the United States as one of the largest oil producers in the world, well, exporters in the world and an energy superpower. These are all terms that have been used by the previous Administration and now this one. So, you know, this hopefully is not a disputed fact, politically. It also conveys tremendous geo-political advantage for the United States. Conversations by councils around the world really do focus largely on the U.S.'s ability to project energy dominance around the planet.

It conveys tremendous advantages in those regards but, and this is actually very important, none of that is going to happen absent the very unique, legal institutions that we have in this country and regulatory facilities that we have in this country. And anything that upsets any of those things, and they're laid out in my written testimony, will actually throw a wrench in the wheel, so to speak. And that can actually keep things from occurring.

I mean, the United States, for example, is the only country in the world where landowners own mineral rights. There's not another one in the world. So that actually gives developers the ability to negotiate directly with landowners and you get this incentive compatibility that triggers development.

Now, that's not enough, right? So geology is a necessary condition. You need that very unique treatment of property rights, but you also need the ability to move and market. And that's something that is unique about the United States.

You look at the natural gas market, for example. It is, arguably, one of the most efficient energy markets on the planet and that owes everything to the ability to expand infrastructure based on pricing signals that are realized because there's real communication between consumers and producers. So anything that gets in the way of that communication can stand to disrupt everything, all the way back through the value chain. And this is actually why earlier, I mentioned, it's important to recognize interrelated nature of all infrastructure because if one thing slips, the whole engine shuts down. And so, it's really important to recognize the efficiencies that the current environment have wrought from the United States.

The CHAIRMAN. Well, I appreciate that.

Let me talk a little more broadly about this cooperative federalism that was raised by several of you. If other colleagues have raised it in their questions, I apologize, as I was out.

But it does speak to some of what we are seeing today. You have a clear need in a region, but you have states, you have municipalities, localities that have, clearly, their view of a particular product or project.

I guess, and I throw this out to any of you who wish to speak to it, obviously Mr. Santa, I would hope that you would. What should Congress be doing in this vein—to ensure that the federal and the state governments respect one another's rules, do not abuse the authority that they each have or the delegation that they have been given under federal laws, recognizing that you have a product, whether it is natural gas, or just use that as an example here, but you need to move it to an area, but you have to move by others? Just the issue that we face in respecting both the state and the federal authority. Given that, what should our role here in Congress be?

Mr. SANTA. Let me begin by saying I think often this issue gets framed in terms of state versus federal roles, and I think it's important to think about it in terms of state versus state.

For example, the fact that the State of New York blocks a pipeline. That deprives Pennsylvania and its citizens of a market for their natural gas and similarly deprives the citizens of the states downstream of that pipeline from the ability to have access to more affordable natural gas. So I think in that sense, it's uncooperative federalism that we are seeing.

I think there are two things that Congress could do. First of all, clarify what is the appropriate role of the states acting under that authority that has been assigned to them. And then second of all, providing some recourse in an event that a state oversteps its bounds or acts in a way that is contrary to the national interest.

For example, under the Coastal Zone Management Act, there is the ability to take an administrative appeal back to the Secretary of Commerce rather than going to a Federal Court where its administrative law standards that are very, very deferential to the agency that took the action. Could something like that be done under the Clean Water Act?

The CHAIRMAN. Anybody else? Mr. Moeller?

Mr. MOELLER. Well, I think Don summed it up quite well. When it's about interstate commerce there's more than just states involved, or individual states, and I think his example with Pennsylvania, New York and the New England states is a very poignant one.

The CHAIRMAN. Very good.

Let me turn to Senator Smith.

Senator SMITH. Thank you very much, Madam Chair.

I am so happy to have a chance to see you all.

I would like to turn to Mr. Mezey and ask you about Itron—sorry, I've been running around this morning—Itron's work on embedding smart technology in the electric grid and how that is helping to improve energy efficiency and also the resiliency of the grid. I sit here as a proud Minnesotan who is very happy to have your company's presence in my state, in Waseca which is one of your, as I understand, one of your best performing manufacturing facilities. So it is wonderful to have a chance to visit with you about this.

I am wondering if you could just talk a little bit about your company's, you know, kind of, what your company is doing in Waseca and how this is working to, sort of, showing the combined importance of both American manufacturing and water and water efficiency.

Mr. MEZEY. Great, thank you, Senator.

A great deal of the discussion about smart technology gravitates toward electricity for a very good reason that electricity can't be stored. It's much more a dynamic market.

Our Waseca facility actually manufactures our gas and water products. And there's a tremendous amount of opportunity for us to improve understanding about gas usage and the performance of gas distribution systems, improve their safety and reliability.

And so, the Waseca facility produces these units that we are deploying so the equivalent of the smart meter on the electric side and the smartgrids—we are building gas smartgrids that are going beyond just the measurement of gas, but actually looking at, as I mentioned, things like corrosion, pressure and even methane detection, in order to improve overall safety and efficiency of the pipelines.

On the water side, not the direct jurisdiction of the Committee, but over 30 percent of water put into the U.S. water distribution system is lost. Water in some states, and California is an example, is the most energy intensive. It represents, it consumes 10 to 20 percent of electricity in the State of California for the pumping purification movement of water and yet, we waste so much of it. So the water smart devices that we're putting out there are allowing utilities to isolate where these water losses are occurring, give consumers better visibility that not only helps our stressed water systems, but also improves the energy efficiency of very large water utilities which is a tremendously, and wastewater, which is tremendously important as well.

So we're very proud that the Waseca facility really is a beacon and the work that we're doing in gas and water efficiency world and really bringing measurement and management to these very important commodities.

Senator SMITH. Thank you very much.

I was struck by the description in your testimony of the Envision Charlotte initiative, and this seemed like this is a public-private collaboration that focuses on improving energy efficiency with smart technology and the really impressive results, it sounds like, in terms of reduced energy consumption, reduced CO2 emissions and also saving money. So it sounds like all around a great thing. Could you just talk a little bit more about that strategy and your role in that strategy?

Mr. MEZEY. Certainly.

I mean, we're so—first of all, it is a public-private partnership, so a very innovative structure that was put together which is being replicated in other cities across the country and was a collaboration of Duke Energy being such a strong local presence and driver.

The technology that we're deploying is an open standards based platform that encourages other types of technologies and devices to share this infrastructure which makes it possible for the downtown area to not only reduce its electricity usage but gas, and now we're bringing water on and integrating with buildings through open standards to integrate into building control systems to balance supply and demand.

So for, really, a very inexpensive additional expenditure to the smart metering infrastructure that we had put in place, we had this dramatic benefit in Charlotte, which as I said, is really a measure of economic vitality for that city and we have tremendous possibilities in cities and this point about rural, about increasing energy efficiency in rural communities as well.

Senator SMITH. Great, thank you very much.

I want to thank all of you for your testimony today. I appreciate it very much.

The CHAIRMAN. Thank you, Senator Smith.

Mr. Moeller, I was asked, I was not here when you were responding to Senator King, but apparently there was an exchange that related to PURPA and I have been asked to ask just for some clarification in responding to Senator King's comment that PURPA does not raise costs.

[Laughter.]

Mr. MOELLER. Well, I probably gave short shrift to the mandatory, I mean, to the avoided cost calculations that are up to states—so they decide the compensation levels of PURPA resources. But the details really matter because if you sign a long-term contract while prices are falling, of a particular resource, then arguably if you would have a shorter contract customers would not have to pay as much. And so, those details matter.

On a larger side though, the mandatory purchase obligation is more significant because we have customers being forced to buy power they don't need. In that sense, the cost of the resource really doesn't matter if they're forced to buy power they don't need. Idaho Power is going to spend $3.1 billion over the next 20 years for PURPA contracts they don't need.

That is the fundamental argument I was making, but again, states have avoided cost calculation responsibilities.

The CHAIRMAN. Good. Well, I appreciate that clarification.

Gentlemen, thank you. You have given considerable time here this morning to the Committee in responding to member's questions. You have given of your time by coming here to the East Coast, several of you, and we appreciate that. And we truly appreciate what you do in your respective sectors.

I think the information here has been helpful, and I know the Committee will be considering it as we move forward with a focus on building out that energy infrastructure that makes this country strong and sound and truly resilient from an energy security perspective. So thank you for all you do.

With that, we stand adjourned.

[Whereupon, at 12:11 p.m. the hearing was adjourned.]

APPENDIX MATERIAL SUBMITTED

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Questions from Chairman Lisa Murkowski

Question 1: **In your testimony, you state that our nation's electricity grid has been called "the most complex machine in the world," and that it is perhaps unappreciated because of its amazing reliability. At our hearing late last month, our committee had a good discussion of the outlook for reliability and the grid's performance during the recent cold weather.**

- **Given your contributions to the study of reliability issues during your many years at FERC, particularly as reliability might be impacted by plant retirements, what are your views on the recent efforts by the Commission to address this issue? How might the resolution of this issue be accelerated? What advice would you offer the Commission and the Department of Energy with respect to this matter?**

I believe the Commission has taken a reasonable approach toward reliability issues. Asking the regions to take a look at resilience issues is reasonable given the differences between the regions in the types of generating resources and differences in energy infrastructure that are deployed. Although this effort should not be rushed, it is important for the Commission to maintain momentum on this set of issues. If the Commission determines that a specific region has challenges pertaining to resilience, it should use its authority to address any such challenge in the most expeditious manner possible and avoid lengthy regional processes. I would recommend that the Commission should keep the Department of Energy fully informed while the Commission undertakes this effort.

The Commission should also accelerate its interest in better coordination of the gas system and electric system. As the nation continues to use more gas to generate electricity, better coordination of these two separate but increasingly converging industries is more important than ever.

- **What should happen on infrastructure policy to ensure that our grid remains both resilient and reliable?**

As outlined in my testimony, a robust electricity transmission and distribution infrastructure provides optionality in the energy grid, which alleviates costly congestion, provides access to lower-cost and increasingly clean generation, increases the reliability and resiliency of electricity delivery, and can flexibly adapt to changes in public policy and sources of electricity generation.

To promote a more robust system, EEI supports streamlining and expediting the process for permitting and siting energy infrastructure—including transmission, natural gas facilities and pipelines, and hydroelectric and other renewable energy facilities—to ensure that energy can get where it is needed, when it is needed. We also support better electric-natural gas coordination. And, we believe it is important that infrastructure policy help support development of smart communities, electric transportation, grid resiliency, and FERC transmission initiatives.

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One of the most significant obstacles to facilitating energy infrastructure investment continues to be obtaining permits from federal agencies. Permitting and siting energy infrastructure on federal lands is subject to a wide array of land-use authorizations and associated environmental reviews. The current permitting process involves multiple federal and state agencies engaging in uncoordinated and sequential project reviews. Lack of interagency cooperation, the absence of deadlines, scarce federal resources, and extensive permit and environmental requirements have resulted in lengthy timeframes and costly processes for project proponents. For example, the average timeframe for permitting and siting an interstate transmission line is on the order of 7 to 10 years.

For any infrastructure policy—either legislative or regulatory—it is critical that existing statutes impacting permitting and siting are updated, improved, simplified, and streamlined so that companies can site and permit critical infrastructure. It also is important that states, localities, and cities are able to use money for public-private partnerships to invest in smart community development.

- **You often talked about the need for transparency at the EPA when it was making decisions that could impact reliability. Now that you are no longer on the Commission, would you similarly call for transparency at FERC?**

Transparency at all agencies improves public confidence and trust in agency decisions. As this current Commission settles into its regulatory rhythm, I expect its transparency to increase. This is especially important in matters relating to reliability and enforcement. For reliability it is important that the Commission is clear why it is proposing and making particular regulatory decisions, including requesting and releasing security-sensitive operational information. It also is essential that the Commission allow time for existing standards (especially relating to Critical Infrastructure Protection) to be implemented before ordering additional iterations of standards to be developed. Regarding enforcement, the Commission should be very clear in providing guidance so that regulated entities know what is expected and are able to receive guidance in areas where there are legitimate questions regarding the appropriateness of certain actions.

Question 2: While this hearing is focused on the "evolution" of our energy infrastructure, I wanted to take a moment to consider the potential "de-evolution" of our nation's nuclear energy infrastructure. I have been concerned with the rapid rate of closures for today's operating nuclear plants. I understand that in the last five years, six units have been shut down, and that utilities have announced plans to prematurely shut down an additional eight units. As you know, losing a nuclear unit does not just represent the loss of the physical assets, it also represents the loss of a highly skilled workforce. If our nuclear workforce shrinks, it will not be easy to reestablish. This would likely have profound implications on our ability to build and operate advanced reactors in the future, to influence global nuclear regulatory and non-proliferation regimes, and to maintain our nuclear national security enterprise.

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- **How concerned are you, and your members, about de-evolution of our nuclear sector?**

Although not all EEI members own or operate nuclear units, there is widespread concern about the future of these plants and maintaining the highly skilled workforce that is necessary. Many of these plants provide environmental and other attributes that, for a variety of reasons, may not be recognized or fully compensated in the wholesale markets. Accordingly, they may not receive the revenue needed to provide long-term stability and reinvestment to keep these valuable units in the generation fleet. I am very concerned about this situation, but am also optimistic that proper support for small modular reactors will result in a new generation of nuclear power that can be viable for decades into the future.

Question 3: You described the need for regulatory certainty to attract sustained investment in infrastructure, raising the topics of Return on Equity, permitting reform, and incentives.

- **Do you think that investors are seeing a risk that FERC will not provide adequate equity returns in the future?**

As noted in both my written and oral testimony, the current uncertainty in these areas is clearly adding risk to these investments, especially as this uncertainty relates to electric transmission projects. With the returns on equity (ROEs) trending below levels allowed at the state-regulated distribution level, these riskier transmission investments are not receiving a commensurate level of return. Moreover, results of the current model used to estimate allowed ROEs are not consistent with the results of other models and market indicators. When EEI talks about transmission infrastructure, we do so with an eye toward the future. Policy changes take time to impact long horizon transmission planning processes, which can take many years.

- **Having recently sat on the Commission, do you think that this is a problem of FERC Commissioners not being able to reach consensus on this issue? Or is it a problem of the FERC process taking much too long to arrive at a decision?**

Given the complexity of these decisions, I expect that the new Commission is working diligently to arrive at a compromise that can be embraced by the entire Commission while the press of other Commission business continues. Over the last several years, the Commission has tended to set these cases for hearing, and the hearing process can drag out over several years. In fact, there are several pending ROE cases; some have been in-process for years. Serial, or "pancaked" challenges to electric companies' ROE have resulted in multiple, overlapping, formal complaints that create investment uncertainty, potentially deterring investment in these types of significant, long-term investments. Transmission owners need timely resolution of ROE issues within reasonable and predictable timeframes.

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- **Given the need for transmission projects, what is the purpose of an incentive rate treatment? Do investor-owned utilities have an insufficient incentive today to take some big risks on getting important transmission lines built?**

I believe Congress, in seeking to end a two-decades-long period of underinvestment in transmission infrastructure, recognized the challenges to transmission investments when it directed the Commission in the 2005 Energy Policy Act (EPAct 2005) to incorporate transmission incentives. The Commission's ability to grant transmission incentives is a tool to support the development of electric infrastructure that provides value to customers, including new and improved technologies to meet evolving customer expectations, improved reliability and flexibility, limiting customer outages during adverse conditions, and lowering energy prices for customers by relieving congestion on the grid and facilitating wholesale market competition. FERC's implementation of its incentives policy has a direct link to developers' responses and, therefore, customer benefits. Investors in transmission assets assume numerous risks and challenges, including long lead times, significant development opposition from affected stakeholders, and extensive state and federal permitting and siting processes. Within the electric power sector, transmission investments differ from other electric company infrastructure investments, including distribution infrastructure, whose projects tend to be smaller in scale, lower in cost, and shorter in duration.[1] Creating greater certainty in this risk climate will help us today and in the future, and I believe there is currently insufficient incentive to take these risks. This is especially true as it relates to inter-regional projects between regional markets.

- **Where should we look for success in permitting reform? Last Congress, in the FAST Act, we codified a streamlined agency permitting process and the Trump Administration has issued an Executive Order calling for a two-year permitting process. Are these solutions working, or should we do more?**

FAST-41 and the Federal Permitting Improvement Steering Council (Council) have the potential to streamline agency permitting processes, but it will take some time to see on-the-ground improvements. The Council needs to oversee more projects to generate institutional efficiencies throughout the agencies. The Council also needs to have an Executive Director appointed to provide the leadership needed to ensure its success. While the Executive Order laid the groundwork for National Environmental Policy Act (NEPA) streamlining, Congress needs to look at ways to improve NEPA implementation through statutory reforms, many of which were included in the White House Legislative Outline for Rebuilding Infrastructure in America released on February 12.

- **Where can we provide faster permitting without compromising environmental standards?**

[1] Opinion No. 531 at P 149. The Commission found that investing in transmission infrastructure is inherently more risky than distribution infrastructure.

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There are numerous areas where the mutual goals of timely permitting and environmental protection can be achieved. In keeping with the FAST Act, all authorizations and associated environmental reviews for infrastructure projects under federal law should be coordinated. There should be a clear lead agency with authority to set a prompt schedule for all agencies involved and to compile a consolidated record of decision. The agencies should be required to avoid duplication of effort and unnecessary delay in reaching decisions. This consolidated process should encompass all federal and state agency approvals and associated environmental reviews, including under the Clean Water Act, the Endangered Species Act, and NEPA. The scope of review should be limited to the authority delegated to each agency and the purpose of the project. These measures would provide for more timely permitting without compromising environmental protections.

- **To what extent does a policy of stopping infrastructure actually have an adverse impact on the environment? Can you provide examples of infrastructure that actually improved the environment by allowing access to cleaner fuels (like wind or solar power)?**

EEI members are committed to meeting customers' needs by building and using smarter energy infrastructure, by providing even cleaner energy, and by creating the energy solutions customers want. This includes access to power generated using renewables and other clean energy resources. For example, the Tehachapi Renewable Transmission Project will connect up to 4,500 MW of mostly renewable resources to help meet California's renewable portfolio standard goals of 33 percent of retail customers being served by renewable generation by 2020. In Texas, the Competitive Renewable Energy Zone (CREZ) initiative installed 3,600 miles of transmission lines to send 18,500 MWs of wind energy throughout Texas. The goal of CREZ is to create the transmission of renewable energy generation from natural resources that will displace dependency on current carbon emitting electrical sources and will support the future growth and long-term needs of Texas. If construction of new energy infrastructure is delayed or blocked, it negates the environmental benefits these projects provide.

In addition, infrastructure projects provide additional environmental benefits beyond their direct or primary designed purpose. Energy infrastructure developers provide millions of dollars for improving wildlife habitat, cultural resources protection, and recreation facilities beyond the project area. As an example, many electric companies and industry-affiliated organizations are pursuing transmission corridor environmental stewardship programs. Also, energy companies are exploring the use of transmission rights-of-ways to provide suitable habitat for pollinator populations and other sensitive species. Programs such as the Electric Power Research Institute's Power-in-Pollinators Initiative provide electric companies with an understanding of how specific vegetation management techniques affect pollinators, thus allowing adjustments to vegetation management strategies to optimize habitats for pollinator benefit.

Question 4: As I am sure you are aware, our Committee has held a number of hearings on the issue of grid security over the past year, covering issues like cyber security, Electro-

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Magnetic Pulse (EMP), weather, and other threats. We've also heard from DOE, FERC, the National Labs, and others about the various groups attempting to address this problem.

- **Are efforts today sufficient to address future threats? Specifically, is the government getting needed information to the utilities, and vice versa, are utilities getting their operational data to government agencies in the best position to act upon it? What else should be done?**

The reliability and resiliency of the energy grid are the top priorities of America's electric companies. Our members take a defense-in-depth approach to meet all hazards – whether manmade or natural, whether cyber or physical security.

Information sharing and information flow are key components of grid security. The industry enjoys a good partnership with government through the Electricity Subsector Coordinating Council (ESCC). Another important industry-government partnership is the work done through the Electricity Information Sharing and Analysis Center (E-ISAC).

The industry is working closely with the Electric Power Research Institute (EPRI) as part of a multi-year research program to understand potential risk and impact associated with EMP, as well as measures and methods that can be implemented to reduce the impact of this low probability but high impact event. We understand from EPRI that they are happy with the cooperation of the government to inform this study.

However, there can always be improvements. Effective sharing is about getting the right information, to the right people, at the right time. There must be a commitment to collaboration between information sharing partners – industry, the government, and our ISAC.

As has been identified in the past, the industry has been challenged in obtaining government provided clearances to allow not only senior management representatives but also operations subject matter experts to receive current threat actor intent and associated risk information. Relatedly, the tendency to over-classify information can impact the speed and availability of information. Electric companies need actionable information, not intelligence gathering sources and methods. Government agencies should work to speed "tear line" information to grid owners and operators as quickly as possible.

The industry remains concerned about information protection challenges associated with providing detailed operational information to the government. When our companies share Critical Energy Infrastructure Information (CEII) with government agencies, they expect that it will be treated accordingly.

<u>Question 5</u>: Investor-owned utilities often face the claim that they have an "incentive" to build out assets, as they can earn a return on their assets.

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- **Can you explain if this incentive to build is a true incentive that goes above and beyond the standard motivation of any profit-seeking company to invest in its business?**

As noted above, there are wide-ranging risks to build these assets. Yet there is competition for capital to invest. If distribution level assets provide less risk at higher returns, the capital is naturally going to flow more towards these investments. This has long-term implications for the necessary investments in the transmission system.

- **How does the incentive of a utility to build transmission assets differ from the incentive of a utility to invest in assets that improve energy efficiency?**

Most transmission investments are regulated by the Commission and are justified by a benefit to cost ratio. Most energy efficiency investments are regulated by state commissions. When state commissions regulate energy efficiency investments, it is essential that a rate structure is developed that allows customers to benefit while at the same time rewarding energy companies that make these investments. In other words, rate structures need to be developed that assure that the energy company making these investments is not harmed by reducing revenues.

Questions from Senator Ron Wyden

Question 1: Hurricanes Maria and Irma reminded us of the vulnerability of our critical energy infrastructure to natural disasters. I want to make sure that steps are being taken to protect Oregonians from the impacts of a disaster such as an earthquake in the Cascadia subduction zone.

What are electric utilities doing to take the lessons learned from the aftermath of Hurricanes Maria and Irma, and use them to increase the resilience of the mainland grid to a massive natural disaster that could affect an area larger than one city?

The reliability and resiliency of the energy grid are the top priorities of America's electric companies. EEI's member companies take lessons learned from natural disasters and implement new practices to get better for the benefit of our customers. Major improvements took place following Superstorm Sandy, including an overhaul of the operation and coordination between Regional Mutual Assistance Groups (RMAGs) and the development of a National Response Event Framework, which allows a national allocation of restoration resources when resource requirements are greater than what impacted RMAGs can provide.

The industry is in the process of conducting after-action analyses from 2017 incidents and will continue to learn from these storms. However, some lessons are already clear.

First, grid investments are making a difference. The industry has invested more than $52 billion in the transmission and distribution system since 2016. While not all of this is directly related to storm hardening, these investments make the system more resilient. The investments made by the sector in smarter energy infrastructure were evident in how quickly power was restored in Florida and Texas. The speed of the recovery was noted by the U.S. Energy Information Administration:

> *"About 15% of customers were without power at noon on September 10, and power outages peaked at 3:00 p.m. on September 11, affecting 64% of customers. In contrast, Hurricane Wilma moved quickly across the southern part of the state, knocking out power to 36% of customers in Florida. Although the percentage of Florida customers without power during Irma was significantly higher than during Wilma, the rate of electric service restoration has been more rapid. Five days after Irma's landfall, the share of customers without power had fallen from a peak of 64% down to 18% (a recovery rate of about 9% of customers per day). Power outages during Wilma declined from 36% of customers to 16% by the fifth day after landfall (an average recovery rate of about 4% of customers per day). ... Since 2005, Florida Power & Light and other utilities in the state have made significant investments to improve their hurricane preparedness. These utilities have upgraded electric infrastructure, including replacing wooden utility poles with concrete poles. Utilities have also deployed smart grid technologies, which provide more timely and more accurate information about outages and can help utilities better target restoration efforts."*
> (https://www.eia.gov/todayinenergy/detail.php?id=32992)

Secondly, industry-government collaboration is critical. The partnership our companies enjoy with the federal government through the Electricity Subsector Coordinating Council has become an invaluable part of disaster preparedness, response, and recovery. The maturity of our relationship with government has resulted in better unity of effort and unity of message.

One emerging area where more government help could be used is to better communicate how drone technology can be used following disasters.

In your view, what should the Federal government be doing to increase the resiliency of the grid to an event such as a major earthquake?

Our companies have done many things, including seismic remediation work on older assets and commissioning redundant fuel supplies at generation sites, allowing for the ability to start the plant when the grid is down (BlackStart).

One important role that the government can and should continue to play is to continue offering opportunities through exercises to test the industry's disaster preparedness. In June 2016, the industry participated in Cascadia Rising, a four-day exercise designed to simulate a 9.0 magnitude earthquake in the Pacific Northwest. These exercises are important in building skills across the sector.

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<u>Question 2</u>: In 2013, Oregon's Department of Geology and Mineral Industries (DOGAMI) issued a report that identified vulnerabilities to the state's Critical Energy Infrastructure hub, which is on a bank of sandy soil next to the Willamette River. DOGAMI noted that, during a major earthquake, that soil could liquefy and severely disrupt fuel and electricity supply lines.

What steps should electric utilities be taking to assess seismic risks to their infrastructure, and implement seismic mitigation plans?

Not all EEI member companies face the same level of seismic threat. We posed this question to some of our members in the most-active seismic areas—including companies in Oregon—and here are some of the responses we received:

- Efforts to address earthquake threats have been conducted through planning, preparedness, and exercises. These include FEMA exercises conducted since 2011.
- Industry and individual company emergency drills are conducted on a routine basis to practice and identify areas for improvement and share lessons learned.
- Companies take assessments and analysis from exercises to develop plans to address threats, define the initial response, and develop protection, mitigation, response, recovery actions, and essential personnel needed to restore after earthquakes.
- Electric company infrastructure is built to local seismic codes and older critical infrastructure is reinforced including equipment such as power transformers and circuit breakers. In addition to seismic codes, critical infrastructure is reinforced or made to be more resilient considering the most common types of contingencies for a given location.

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- Integrate seismic resiliency into existing capital plans.
- Perform seismic risk assessment of critical system infrastructure.
- Implement focused projects to mitigate seismic risk either by hardening facilities or building in redundancy.

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- Establish a hazard assessment and mitigation program/effort that:
    - Looks broadly at infrastructure and business processes that can be affected by an earthquake
    - Assesses seismic risk using a tiered process
        - Screening to identify vulnerabilities
        - Site Specific Probabilistic hazard analysis
        - Prioritize risk by looking at system risk based on likely scenarios
    - Develops a consistent mitigation approach based on impact not components

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- Based on the hazard analysis conducted in the previous series of steps develop preparedness and response plans and programs:
  - Preparedness
    - Programs to prepare employees at work and at home
    - Alternate facilities (if necessary)
    - Communications
    - Mutual Assistance
    - Programs to assure adequate stores of key materials
  - Response
    - Develop response plan based on the hazard analysis
    - Coordinate plan development with State office of Emergency Services, cities, counties and other critical infrastructure providers such as Communications and Water/Waste Water; (The State has a plan for response to a Cascadia EQ)
    - Align response plans and associated response structures to National standards
    - Drill and exercise plans collaboratively with key stakeholders

Questions from Senator Joe Manchin, III

<u>Question 1</u>: The decline of the coal industry has been devastating to my home state. We lost businesses and population. So we are looking for ways to revitalize our home state economy. I have been working for some time with Senator Capito to bring stakeholders together to help realize the potential of an Appalachian Storage Hub – an innovative energy infrastructure project that will attract manufacturing investment and create jobs. Our area is primed for this sort of energy project because of our abundant natural gas, natural gas liquids and natural geologic storage. This is exactly the type of effort is what Congress envisioned when it created the Title Seventeen loan program. The Loan Program Office (LPO) helps provide low cost capital to innovative energy projects in order to help alleviate investor concerns and get the project into development. The future of this program is currently in question though. So I'm concerned that Congress is going to unwittingly tie the hands of many energy infrastructure projects – not just this one – if we don't ensure this program is funded going forward.

As you reviewed the evolution of energy infrastructure in this country, do you believe the US government has had a role in innovating us to the next stage?

Yes. For example, in 2009, as part of the American Recovery and Reinvestment Act (ARRA), Congress created the new Section 1705 Loan Guarantee Program, which authorized DOE to guarantee loans for renewable energy systems, leading-edge biofuels projects, and electric power transmission systems, regardless of whether such projects employed "new or significantly improved technology". The Section 1705 program required projects to have commenced construction and reached financial close by September 31, 2011. Additionally, the ARRA

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appropriated $6 billion for the credit subsidy cost (CSC) of loan guarantees issued pursuant to Section 1705, which relieved borrowers from being responsible for full and upfront payment of the CSC upon closing, an amount that could be a significant percentage of the loan. While a portion of the CSC monies ultimately were used to offset other projects, including the "cash-for-clunkers" effort, Section 1705 still was critical in helping expensive and high-risk projects to receive approvals from utility regulatory commissions and to obtain additional private sector funding.

Is it fair to say that the loan program has had a profound impact on the evolution of how electricity is produced and delivered in this country today?

The Section 1705 program was critical in getting new nuclear projects approved in the early 2010s. Additionally, these loans have been instrumental in increasing the share of renewable energy resources for electricity generation over the past 10 years. Many of these renewable energy projects, primarily large solar plants, were developed with these loans. Most of these projects had power purchase agreements (PPAs) with EEI member companies. A few of EEI's members also received loan guarantees directly, especially in California, Nevada, and Arizona for solar projects. While there has been a significant reduction in cost of some of these technologies, some projects may continue to have regulatory risks or customer benefits uncertainties.

According to DOE's Loan Office Programs website, updated as of June 2017, the following types of projects have received loan guarantees (Examples of EEI member company involvement in parentheses):

- Wind: 4 projects
- Nuclear: 1 project (Southern Company)
- Photovoltaic solar: 6 projects (Exelon, NextEra, Sempra & ConEd)
- Concentrated solar power: 5 projects (NextEra)
- Storage and transmission: 2 projects (NV Energy)
- Geothermal: 3 projects

<u>Question 2</u>: On January 28, the Washington Post reported that a tanker carrying liquefied natural gas (LNG) from Russia arrived in Boston Harbor. That tanker had gas on it from the Yamal facility – a project largely financed by the Russian company Novatek. In July of 2014, after Russia annexed Crimea, the US Treasury Department issued sanctions that were specifically targeted at weakening the Russian energy sector – those sanctions forbid any financing for projects belonging to Novatek. Recognizing Boston was not its first step along the journey, it seems though that these sanctions do not prohibit the purchase of gas from this Russian project in the Arctic. So – in short – there is Russian LNG being turned back into gas at one of our ports and then being used to power American homes. Earlier this week, the Energy Information Administration released its Annual Energy Outlook for 2018. In the Reference case, natural gas production accounts for the largest share of total energy production - 39% by 2050. That's domestic fuel.

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My question is simple: Why, when we have one of the world's greatest reserves of natural gas sitting right under West Virginia, are we importing it at the risk of bolstering Russia's energy sector?

My answer is also relatively simple: there is insufficient pipeline capacity to move domestic gas to the markets that need it. As noted in other answers, siting and permitting reform is needed, and these reforms can be addressed both by federal agencies through administrative reforms and by Congress through statutory reforms.

Question 3: Following the Bomb Cyclone, this Committee held a hearing on grid performance. Andy Ott, the chief executive officer of PJM – the regional transmission operator which includes West Virginia – and I discussed how critical coal-fired power plants were to keeping the lights on and houses warm. In fact, Mr. Ott agreed that we couldn't have done it without coal. During that hearing we also discussed how well natural gas fired generation performed – unfortunately we also witnessed price spikes due to limited pipeline capacity. It seems to me that if we want to fully realize an "all of the above" energy future, we must utilize our abundant supplies of natural gas by ensuring that natural gas can get to areas of demand – like the northeast. That means responsible expansion of pipeline infrastructure.

How do we enhance coordination and collaboration amongst permitting agencies? Because it seems to me that – in many instances – to secure one permit you to have secure three others first. And if those agencies aren't talking to one another, a pipeline developer becomes a go between.

Barriers to obtaining federal permits in a timely manner continue to delay the siting and construction of new energy infrastructure, including pipelines and electric transmission lines needed to maintain reliability, enhance resiliency, and deploy clean energy. Enhanced interagency coordination is critical to overcome these barriers. The current administration and the two previous administrations have recognized this and launched initiatives to improve the federal infrastructure permitting process.

As discussed in my response to a similar question from Chairman Murkowski, we believe FAST-41 and the Federal Permitting Improvement Steering Council have the potential to streamline agency permitting processes, but it will take some time to see on-the-ground improvements, and the Council also needs an Executive Director in place to provide the leadership needed to ensure its success. While the groundwork for NEPA streamlining is being laid through administrative actions, Congress also should consider statutory reforms to improve NEPA implementation similar to those outlined by the White House in its February 12 proposal.

In your opinion, will improved policies for firm contracts for natural gas help?

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Siting and permitting reforms, as outlined in my testimony and by other witnesses, is the first step that Congress and agencies can take to help ensure that additional pipeline infrastructure gets built. Any proposed changes to the financing of natural gas pipelines, if needed, can be addressed by FERC in the larger context of resilience and electric–gas coordination.

<u>Question 4</u>: **In October of last year, your organization along with a handful of others wrote to the Senate to express the need for legislation that provides a stronger framework for vegetation management and other types of maintenance of electric infrastructure on federal lands. The letter stated that "Managing vegetation on electric transmission and distribution rights-of-way is a key part of electric company efforts to protect the security and reliability of the energy grid." It also can help reduce wildfire risk, thereby increasing public safety and worker safety. I've heard from numerous stakeholders about the challenges associated with vegetation management on federal land and the primary complaint is that it can be very difficult to get timely approval to implement and execute vegetation management plans, some of which are routine operation and maintenance activities, on federal lands. Such lack of action within the agencies has resulted in electric utility work delays and stoppages on federal lands - often due to a variety of factors, including narrow and inconsistent interpretations of NEPA related to tree removal and other activities on the corridor.**

(a) How much of vegetation management is routine maintenance?

Virtually all of vegetation management is part of routine "operations and maintenance" (O&M) activities in the sense that related activities are performed on a regular, planned basis and are aimed at preventing hazards from developing. Most routine maintenance activities conducted by EEI members are primarily related to vegetation management actions that proactively address potential vegetation hazards within and adjacent to the rights-of-way. Other O&M activities, such as upgrading, repairing, or modifying existing infrastructure for system reliability or stability purposes, occur on an as-needed basis.

(b) Is there a risk that these delays have reached a point where they are causing unnecessary hazards to life, natural resources, and property, as well as power outages?

Managing vegetation on electric transmission and distribution rights-of-way is done in the context of overall risk management and ideally is performed proactively to prevent hazards from developing. The purpose of industry's efforts to minimize or eliminate challenges associated with vegetation management on federal lands is to facilitate access to proactively, rather than reactively, address any hazards before they become a threat to life, resources, or property. Delays in federal agency authorizations for utilities to undertake such vegetation management increase the risk that vegetation hazards will develop. Even with careful vegetation management, however, background conditions, such as the widespread drought and pine bark beetle infestations in the West, may still lead to wildfire risks and other problems that cannot be fully eliminated. But, allowing vegetation management to proceed without unnecessary delays can help to reduce that risk.

(c) Is there a cost to electric utility customers when these rights of way are not appropriately maintained?

When vegetation within utility rights-of-way, and on the lands surrounding those rights-of-way, is not appropriately maintained, it can end up falling or being blown by storms into utility facilities or getting swept up by wildfires that can damage the facilities. In turn, that can lead to power fluctuations, interruptions, and even outages. Electricity customers not only have to pay for damages to the transmission and distribution facilities that serve them, but they are also impacted by power outages. In comparison, the cost of performing routine vegetation management to prevent power outages and wildfires is relatively low.

Questions from Senator Catherine Cortez Masto

Question 1: My state is a big proponent of battery technology. We are home to a large battery factory (Tesla Gigafactory) and Nevada recently created an "Energy Bill of Rights" that protects home energy generation and storage. Thanks to declining costs, better technological, and a growing industry, battery storage deployment at a utility-scale is accelerating at a rapid pace.

- **How can the U.S. be a leader in utilizing this technology, and in so doing increasing grid reliability and clean energy while reducing costs to the ratepayer?**

In the U.S., electric companies are the largest users and operators of energy storage, representing more than 98 percent of active energy storage projects. They are using storage for a wide range of purposes that result in improved operation of the energy grid; increased reliability, resiliency, and operational flexibility; and the integration of more solar and wind power. Energy storage, deployed at the appropriate scale, can position the U.S. as an energy storage leader while enhancing electric company operations, optimizing and supporting the energy grid, and enhancing the customer experience.

For the U.S. to ensure its leadership role on energy storage while enhancing electric companies' operations, grid optimization and support, and enhancing the customer experience, it is important to recognize the active participation of different stakeholders in its deployment. Energy storage provides benefits to electric companies and the grid, as well as customers and third parties. In addition to removing barriers (see response to the next question below), ensuring that electric companies may own or participate in the deployment and management of these resources is the single most effective way to promote sustainable deployment of energy storage. Electric companies, as grid owners and operators, are best positioned to maximize the reliability, resiliency, and operational benefits of energy storage, which can maximize the value of energy storage and make the deployment of storage more cost-effective for customers.

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- **What barriers exist for battery storage deployment and how can the government address those barriers?**

There are several barriers to battery storage deployment in the U.S., the most important of which are related to cost, lack of information on technical performance, and regulatory hurdles. A more detailed discussion of some of these barriers, and policy recommendations on ways to overcome them, is provided below:

Barrier 1: Cost
While some storage technology costs are decreasing rapidly, it is critical to remove other barriers to energy storage adoption, so that the full range of benefits of energy storage can be realized as these resources become more prominent. Although energy storage devices can provide multiple energy grid services in different markets, they often cannot capture all value streams due to existing market performance requirements and code-of-conduct restrictions. The ability of energy storage to become cost-competitive and meet various performance requirements would help monetize all value streams and realize the full economic potential. FERC and the different RTOs/ISOs are already addressing this.

DOE's research and development program has an important role to play in improving technologies' performance and cost-effectiveness.

Barrier 2: Uncertainty Regarding Technical Performance
Widespread adoption of energy storage systems depends upon greater information and certainty about their performance. Experience with some newer technologies is limited, so there are incomplete or unreliable data on their performance. Extending pilot programs where electric companies and other stakeholders accumulate and share experiences can be a critical factor in expanding knowledge and the general acceptability of energy storage.

Barrier 3: Regulatory Challenge A – Classification and Flexibility
Asset classification rules at the state and federal levels, which are often based on traditional single-purpose categories, may need to be updated to accommodate resources like storage that are able to provide multiple services.

Barrier 4: Regulatory Challenge B – Ownership
In some regions, classification rules are also a concern regarding ownership of energy storage. In restructured markets where storage is classified as generation and electric companies are barred from owning generation assets, electric companies may not be able to invest in energy storage devices, effectively eliminating an important option to enhance the reliability and resiliency of the energy grid to the benefit of all customers. This can also have cost impacts, as new storage technologies have the potential to defer or to reduce the need for incremental or additional grid investments.

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Barrier 5: Regulatory Challenge C – Interconnection and Operation
Electric companies are responsible for interconnecting and operating new energy storage devices safely and reliably. Studies that have analyzed the impact of the new interconnections generally assume energy storage devices to charge and discharge at times inconsistent with actual operations. Like all resources that interconnect to the energy grid, energy storage device manufacturers or vendors should be required to define the parameters under which their products are designed to operate. FERC, RTOs, and individual states should continue to work toward removing barriers that artificially limit the ability of energy storage resources to provide the services they are technically capable of.

Question 2: As we look at the evolution of our nation's energy infrastructure, I think it is important to factor into that equation the linkage between energy production and water usage. This is particularly important to a western state like mine where we are water challenged. How do you factor in the availability of water when you make decisions about siting power generation facilities?

Nearly all energy production requires a reliable, abundant, and predictable source of water for diverse purposes, including cooling, hydropower, mining and extraction, fuel production, and emissions control. Water requirements for electric power generation are highly variable. These requirements are influenced by the type of plant, fuel, and choice of the power plant cooling system. Other factors influencing water use include but are not limited to the local climate, the source of water, and the environmental regulations to which the plant is subject.

When siting power generation facilities a myriad of factors are considered. The energy sector often competes with population growth, agricultural and municipal needs, as well as ecological functions and water quality concerns. Consequently, new plant siting is often constrained by access to adequate and reliable water supply. Power is often assigned the lowest priority in regional water resource planning after residential, commercial and agricultural uses. Considerations must be balanced with the intent to optimize land acquisition, transmission routes, water availability, ecological concerns, etc. These and other considerations are included in permitting and discussions with federal, regional and local planning officials.

The electricity sector has long invested in intensive R&D to provide decision support tools for improved water supply and demand planning and technological innovation related to water use and efficient reuse of water. The industry is exploring the use of degraded water use, advanced water-conserving cooling, and customer tools such as energy efficient incentives to improve water use. Water use for power generation has declined per unit of power produced due to efficiencies achieved but challenges remain. Risk related to water availability and use can significantly affect reliability and resilience of energy systems, so the design, planning, regulatory and policy development surrounding energy production requires careful coordination with government officials, the public and energy companies.

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Question 3: How do you factor in the impact these facilities will have on future water supply and reserves and the impact this will have on other local water that is available for consumers?

See response to Question 2 above.

Question 4: How are you compensating for changes in water availability and the potential declining supply of water as you make decisions about building future energy production facilities?

See response to Question 2 above.

Question 5: Regarding wildfire, do you factor in the current and future risks associated with the placement of these transmission lines to include the increased risk of wildfire, especially as our arid regions of the west become warmer and drier?

States oversee siting and permitting of most transmission lines, and federal agencies oversee siting and permitting on federal lands. Transmission lines are designed to be in operation for more than 50 years. Wildfire potential is one of many factors that are considered when evaluating routes for a new transmission line. Wildfire risks along a transmission right-of-way are likely to fluctuate over the operational lifespan of a line, driven by factors such as a drought and pine bark beetle infestations. Federal land agencies and other landowners play a vital role in managing vegetation on their lands to reduce wildfire risk. Also, ensuring that electric companies can perform routine and emergency maintenance on and near rights-of-way without unnecessary delays by federal and state agencies is critical as the companies seek to reduce potential vegetation hazards. Timely maintenance activities in and around rights-of-way for bulk-power transmission lines subject to mandatory North American Electric Reliability Corporation (NERC) reliability and vegetation management standards is particularly critical to ensure compliance with these standards.

Question 6: We are on the cusp of a global electric vehicle boom. Almost every major automaker has announced plans to significantly shift their focus from internal combustion engines to electric in the next few years if they haven't already. Can you discuss how utilities are approaching the impending load growth as a result of increased EV deployment? Do you also see this as a major opportunity?

Electric companies have, and will continue to, operate the electric grid to provide safe, reliable, and affordable power to customers. Electric companies remain committed to working across all levels of government, and with other stakeholders – including electric vehicle (EV) manufacturers – to ensure the successful deployment of electric vehicles and related charging infrastructure. Where needed, electric companies are also working to ensure that the appropriate "make ready" infrastructure is available for EV charging. Electric vehicles are a win-win that

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benefit customers, the environment, the economy, and grid reliability. For additional information, see the attached EEI report entitled "Accelerating Electric Vehicle Adoption."

Question 7: Has the utility industry thought about how it can be leading deployment of charging infrastructure in corridors to meet the needs of increasing EV penetration?

EV charging along travel corridors/major highways is one of the areas that electric companies are well-suited to support. As "fast" EV charging along travel corridors typically results in high levels of electricity consumption, electric company engagement is particularly important to ensure cost-effective implementation. For additional information, see the previously mentioned EEI document, "Accelerating Electric Vehicle Adoption."

Question 8: How can the utility industry assist in ensuring EV operators in urban environments, multi-unit dwellings, and rentals can have reliable access to home charging, where the vast majority of charging happens?

Electric companies, in collaboration with others, are undertaking a variety of approaches to deploying and installing EV charging infrastructure so that all customers have access. In some states, electric companies have received regulatory approval to install charging units in multi-unit dwellings, for example. For additional information, please see the previously mentioned EEI document, "Accelerating Electric Vehicle Adoption."

Question 9: I have been working to garner the support of various entities for my legislation called the Moving FIRST Act. This bill reinitiates the DOT's smart cities challenges to create more opportunities for communities of all sizes to work with private partners to collaborate and address individual challenges that communities large and small want to address. That includes the continued expansion of electric vehicles, which is a fundamental element of the kind of applications I hope this grant challenge will address – to increase energy efficiency and reduce the transportation sector's carbon footprint. Do you think this is a concept your members would find of interest or support?

EEI members are very supportive of smart community efforts that help drive efficiencies, improve sustainability, spur economic development, and enhance the quality of life for citizens. As the trend toward smart communities continues to grow, increased electric transportation (passenger cars, electric buses, and electric street cars) is a major component. Smart communities require collaboration among electric companies, community leaders, universities, technology companies, other business partners, and customers to be successful.

Electricity is the common element in all smart communities. Electric companies – as key pillars of the community and managers of the energy grid – are critical to the success of smart community efforts. The EEI document, "Examples of Smart Communities in Action," summarizes how electric companies are working with 18 cities across the U.S. on smart communities initiatives.

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Question 10: Are you able to be flexible enough to work with local jurisdictions to help them improve their transportation or energy sectors with support from the federal government?

There are a variety of federal programs that encourage public-private partnerships related to the deployment of advanced technology, electric transportation, and other resources that allow for states and local entities to improve transportation infrastructure and address the energy needs of that state or region. Electric companies remain committed to working with all stakeholders, including local jurisdictions, to improve transportation and to ensure that the electric grid remains safe, resilient, reliable, and affordable.

Question 11: In addition to EVs, what other technologies do you see being promoted for the smart communities that are cropping up throughout the country?

Smart communities include things such as smart street lighting, smart traffic lights, smart buildings, smart electric transportation (besides just EVs), and other technologies. Electric companies will continue partnering with local and state stakeholders on smart community efforts that provide a variety of benefits to citizens. See EEI document, "Examples of Smart Communities in Action."

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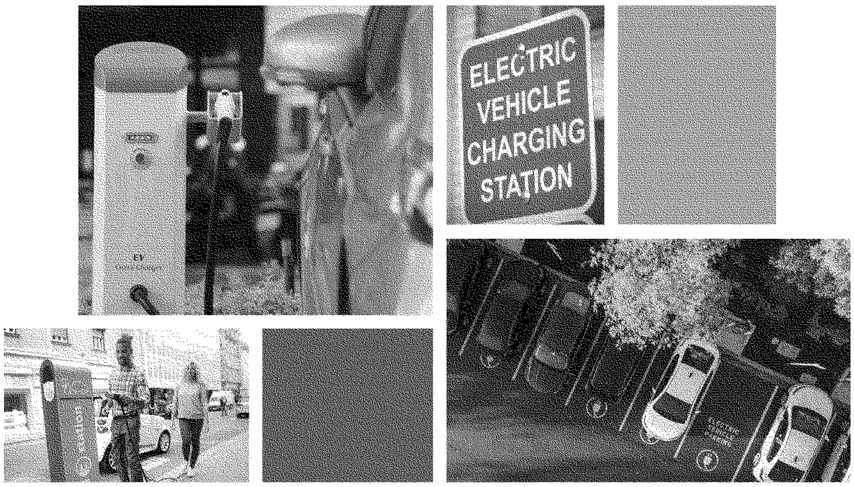

Accelerating Electric Vehicle Adoption

February 2018

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CUSTOMER SOLUTIONS
ELECTRIC TRANSPORTATION

Accelerating Electric Vehicle Adoption

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Executive Summary

Electric vehicles (EVs) make sense for customers and for the nation, but the transition to EVs is in its early stages and requires supportive policies to overcome barriers to adoption.

- EVs provide environmental, customer, energy grid, and national security benefits. This is due, in part, to an energy mix that is domestically produced and increasingly clean.
- Transportation electrification has made notable progress, not only in the passenger vehicle market, but also in a wide variety of commercial applications and non-road uses. While the long-term trends point toward increased electrification, policy drivers and industry action in the near-term will determine the nature and speed of widespread adoption.

Electric companies play an integral role in accelerating transportation electrification in a manner that provides customer value and efficient integration into the energy grid.

- Customer value: Electric companies are well-suited to expand electrification across multiple transportation modes and to expand access to EVs for the benefit of customers and communities. Electric companies can help provide a foundational system of charging infrastructure that supports the needs of customers, while also supporting a reliable, consistent, and positive customer experience.
- Grid integration: Electric companies are responsible for integrating transportation load in a manner that benefits the energy grid and the customers who rely upon it. Electric companies are well-suited to help manage the transition to electric transportation in an efficient and cost-effective manner.
- Accelerating the transition: Electric companies can help accelerate the transition to electric transportation and the resulting benefits for customers and society. Electric companies' existing relationships with customers allow them to grow familiarity and interest in electric transportation. Electric companies also can deploy capital to spur the growth of charging infrastructure that is critical to enabling widespread transportation electrification.

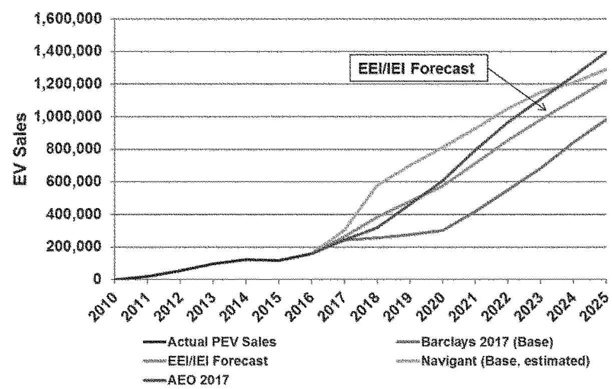
Given the value of EVs and the integral role that electric companies play, policies that enable electric company involvement and investment in the EV market will result in value to customers, greater access to EVs for more customers, more efficient use of the energy grid, and an accelerated transition to an electric transportation future.

Introduction

The transition to electric vehicles (EVs) is well-underway. As of December 2017, more than 765,000 EVs have been sold in the United States, and robust sales are expected to continue.[1] The Edison Electric Institute (EEI) and the Institute for Electric Innovation (IEI) project annual EV sales to surpass 1.2 million by 2025, reaching more than seven percent of annual U.S. vehicle sales in the U.S. by 2025 (see Figure 1). In total, EEI and IEI project a stock of seven million EVs on the road by 2025.[2]

Recent automaker announcements of forthcoming EV models by BMW, Ford, General Motors, and Volkswagen, among others, and technology investments have resulted in upwardly revised forecasts.[3] Bloomberg New Energy Finance, for example, revised its global EV outlook forecast to 54 percent of new car sales by 2040, up from its previous forecast of 35 percent.[4] The EEI/IEI forecast ends at 2025; after that date, other forecasts project exponential sales in EVs.

Figure 1: Annual EV Sales by Year (2010-2025)



Source: Edison Electric Institute (EEI) and the Institute for Electric Innovation (IEI), *Plug-in Electric Vehicle Sales Forecast Through 2025 and the Charging Infrastructure Required* (June 2017), www.edisonfoundation.net.

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1 Sales data from InsideEVs.com and HybridCars.com.

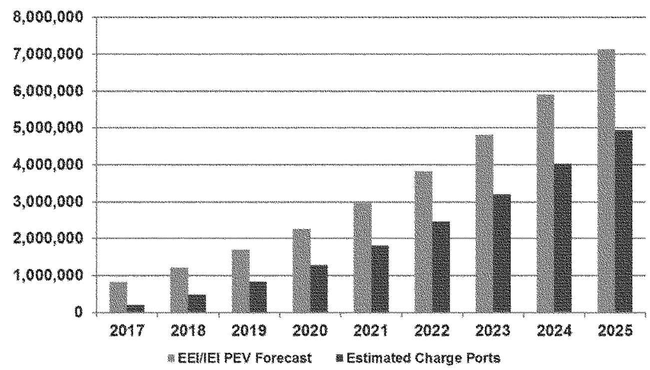
2 Edison Electric Institute (EEI) and the Institute for Electric Innovation (IEI), *Plug-in Electric Vehicle Sales Forecast Through 2025 and the Charging Infrastructure Required* (June 2017), http://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20PEV%20Sales%20and%20Infrastructure%20thru%202025_FINAL%20(2).pdf

3 *See, e.g.*, Alex Davies, *General Motors is Going All Electric*, WIRED (Oct. 2, 2017), https://www.wired.com/story/general-motors-electric-cars-plan-gm; Andreas Cremer, *Volkswagen spends billions more on electric cars in search for mass market*, REUTERS (Sept. 17, 2017), https://www.reuters.com/article/us-autoshow-frankfurt-volkswagen-electri/volkswagen-spends-billions-more-on-electric-cars-in-search-for-mass-market-idUSKCN1BM296.

4 Bloomberg New Energy Finance, *Electric Vehicle Outlook 2017* (July 2017), https://about.bnef.com/electric-vehicle-outlook/.

Growing customer demand, Corporate Average Fuel Economy (CAFE) standards, and declining battery costs are all major drivers of EV sales. However, as the number of EVs on the road continues to grow, so does the demand for charging infrastructure. The EEI/IEI report estimates that about five million charge ports will be required to support the seven million EVs on the road in 2025 (see Figure 2).[5] Although the vast majority of EV charging is expected to occur at home or at work, making charging infrastructure available in public settings and on highways allows EV owners to drive more miles on electric, enables longer trips, and reduces range anxiety.

Figure 2. EV Stock and Charging Infrastructure (Charge Ports) Needed (2017 – 2025)



Source: Edison Electric Institute (EEI) and the Institute for Electric Innovation (IEI), *Plug-in Electric Vehicle Sales Forecast Through 2025 and the Charging Infrastructure Required* (June 2017), www.edisonfoundation.net.

EVs are more than just passenger cars. Electric transit buses have become increasingly popular as transit agencies recognize the fuel cost savings of running buses on electric power.[6] Electric-powered medium- and heavy-duty trucks also are coming to market.[7] In addition, autonomous vehicles are expected to become an important part of the EV market. Automakers and technology companies

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[5] *See* n.2, *supra*.

[6] *See, e.g.*, U.S. Department of Transportation, *Race to Zero Emissions: Zero Emissions Bus Operators*, https://www.transportation.gov/r2ze/fleets-zero-emission-buses-us-and-china.

[7] *See, e.g.*, Joann Muller, *Cummins Beats Tesla to The Punch, Unveiling Heavy Duty Electric Truck*, FORBES (Aug. 29 2017), https://www.forbes.com/sites/joannmuller/2017/08/29/take-that-tesla-diesel-engine-giant-cummins-unveils-heavy-duty-truck-powered-by-electricity; Joseph White, *Navistar, VW Will Collaborate on Electric Truck, Connectivity*, REUTERS (Sept. 25, 2017), https://www.reuters.com/article/us-autos-trucks-volkswagen-navistar/navistar-vw-will-collaborate-on-electric-truck-connectivity-idUSKCN1C02HD.

testing autonomous vehicles today are pairing the technology with electric powertrains.[8] Longer-term, autonomous fleets also could benefit from the lower operating costs of electric power.[9]

Benefits of Electric Vehicles

EVs provide major benefits for the environment, for customers, for the nation's energy grid, and for national security.

- **Environmental Benefits.** Electric transportation reduces carbon dioxide (CO_2) emissions.[10] This is due to an increasingly clean energy mix. As of year-end 2016, the electric power industry's CO_2 emissions were nearly 25 percent below 2005 levels. And, for the first time in more than 40 years, CO_2 emissions for the power sector were below CO_2 emissions for transportation (see Figure 3).[11]
- **Customer Benefits.** The number one benefit to customers is fuel-cost savings. EVs are cheaper to operate than gasoline vehicles, primarily due to the lower cost of electricity on an equivalent cost basis, but also due to lower maintenance costs.[12]
- **Energy Grid Benefits.** EVs, coupled with managed charging, result in more efficient utilization of the energy grid, which lowers the average cost to serve for all customers.[13]
- **National Security Benefits.** When EVs plug in, they are 100 percent powered by a domestic mix of energy sources, including natural gas, coal, nuclear, hydropower, wind, and solar. This is in stark contrast to gasoline-fueled vehicles, which depend solely on oil—only 40 percent of which is domestically produced.

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[8] *See, e.g.*, General Motors, *GM Scales Autonomous Vehicle Fleet to 180 Electric Cars* (June 13, 2017), http://www.generalmotors.green/product/public/us/en/GMGreen/greener_vehicles.detail.html/content/Pages/news/us/en/gm_green/2017/0613-autonomous.html.

[9] *See, e.g.*, Charlie Johnson and Jonathan Walker, *Peak Car Ownership: The Market Opportunity of Electric Automated Mobility Services*, Rocky Mountain Institute (2016), https://www.rmi.org/wp-content/uploads/2017/03/Mobility_PeakCarOwnership_Report2017.pdf.

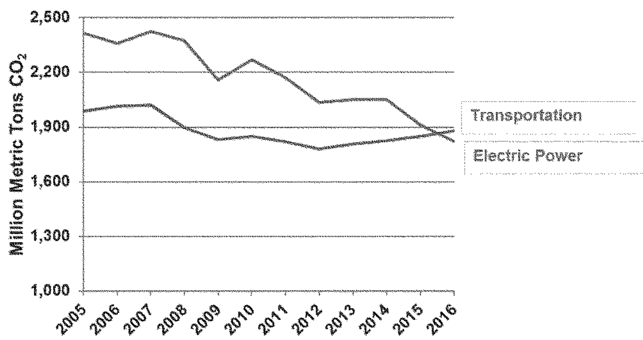
[10] Widespread transportation electrification would result in a 48 percent to 70 percent net reduction in greenhouse gas emissions between 2015 and 2050, as well as widespread air quality benefits. See EPRI, NRDC, *Environmental Assessment of a Full Electric Transportation Portfolio* (September 2015), https://www.epri.com/#/pages/product/3002006881.

[11] *See* U.S. Department of Energy, Energy Information Administration (EIA), *Monthly Energy Review* (Aug. 2017), https://www.eia.gov/totalenergy/data/monthly.

[12] Union of Concerned Scientists, *Going from Pump to Plug (2017)* (November 2017), https://www.ucsusa.org/clean-vehicles/electric-vehicles/ev-fuel-savings.

[13] *See, e.g.*, Energy Environmental Economics (E3), *California Transportation Electrification Assessment, Phase 2: Grid Impacts* (October 2014), http://www.caletc.com/wp-content/uploads/2016/08/CalETC_TEA_Phase_2_Final_10-23-14.pdf.

Figure 3: U.S. CO_2 Emissions from Electric Power and Transportation Sectors



Source: EIA, *Monthly Energy Review* (November 2017), https://www.eia.gov/totalenergy/data/monthly.

While the benefits of electric transportation are clear, more widespread adoption of EVs requires policy support. To date, policy has been an important driver of initial EV market growth, including:

- The Zero Emission Vehicle (ZEV) program. Adopted by California and nine other states (Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, and Vermont), the ZEV program requires automakers to sell an increasing number of qualifying vehicles in those states, driving automaker investment priorities, EV model availability, and deployment.
- Federal fuel economy and greenhouse gas standards. Although not specifically aimed at EVs, these standards influence automaker investments because EVs help automakers comply with them.
- Federal and state purchase incentives. These incentives help lower the up-front cost of EVs, providing a near-term bridge to cost-parity with gasoline-fueled vehicles.

These policies and others are needed to continue EV market growth, but states and communities wishing to further accelerate EV adoption have important strategic partners—electric companies. Electric companies are well-positioned to address some of the primary barriers to adoption, including low customer awareness and the lack of charging infrastructure.

Electric Company Role

Electric companies can expand customer access to EVs, integrate EVs into the energy grid in an efficient and cost-effective manner, and accelerate the transition to widespread EV adoption—all in a way that is beneficial to all customers.

Expand customer access to EVs

Electric companies can help make EVs available to all customers and can address the need for broad access to EV charging. Electric companies also can help expand the use of EVs across multiple modes of transportation, including passenger vehicles, fleets, trucks, and buses, by lowering barriers to charging infrastructure, which is one of the primary barriers to EV adoption.

Electric companies can help bring EVs to communities that may not otherwise have access. Specifically, electric companies are well-positioned to provide access to disadvantaged communities. For example, environmental justice organizations supported electric company investment in California in part because these communities are disproportionately exposed to the negative air quality impacts of transportation.[14] Electric companies also can support the build-out of public charging infrastructure that can be used by car-sharing or ride-hailing programs, providing the benefits of EVs to those who may not even own a car.

Electric companies can support and help develop a system of charging infrastructure that works. Home and workplace charging must be easy and affordable since this is where most charging occurs. While public charging accounts for a relatively small share of overall EV charging, its availability helps to alleviate "range anxiety" concerns. Public charging also can provide a solution for EV drivers who do not have dedicated parking, as well as long-distance travel along major corridors. Electric companies, in partnership with automakers, policymakers, and other stakeholders, can help fill in the gaps based on the unique geographic and market needs of their service territories.

Public charging must be accessible and easy to use and must provide EV drivers with a consistent and positive charging experience. Critical elements include:

- a seamless charging network experience, including a simple payment system, such as a credit card or point-of-purchase option; and
- open network and communication protocols to ensure flexibility and choice.

Interoperability, standardization, and a seamless experience are important to the EV driver, but these become even more important when public funding or electric company customer funding is deployed to protect the interest of all customers. Electric companies have the expertise and the experience to drive the development of industry standards, best practices, and norms.

Integrate EVs into the energy grid in an efficient and cost-effective manner

The flexibility of EVs to charge at different times, locations, and power levels can lead to a more efficient use of the energy grid, providing benefits to all customers. For example, electric companies can send price signals to encourage customers to charge their EVs at night to increase energy grid

[14] *See, e.g.*, Greenlining Institute, *Electric Cars and Trucks: Charging Ahead*, http://greenlining.org/issues-impact/environmental-equity/electric-vehicles.

utilization or to increase wind energy utilization. Or, in states with excess solar energy, electric companies might send price signals to encourage EV charging during hours of peak solar production.

As EV adoption grows, both the energy grid and the electric company, as the integrator of energy resources, become more important. Programs that encourage charging to occur when the energy grid has available capacity will minimize costs and help the grid operate more efficiently—effectively lowering the average system cost for all electric customers.[15]

Electric company investment in EV charging provides an opportunity for "managed" charging solutions that benefit both customers and the energy grid. EV charging can be managed in multiple ways, including customer education, rate design, and "smart charging" that enables communication among the energy grid, the EV, and/or the charging equipment. Electric companies currently are testing multiple charge management strategies, including those that complement approaches used to integrate renewable and distributed energy resources.

Electric companies play an essential role in siting charging infrastructure where the energy grid has the capacity to support it and in helping customers to understand the cost implications for new installations. It is important that charging infrastructure developers and fleet operators work closely with electric companies as partners on charging project implementation. For example, as more high-powered DC fast chargers are deployed, and as fleet owners seek to charge multiple vehicles at single locations, the capacity of the energy grid is an important consideration.

As the EV market grows and the energy grid increasingly powers transportation, electric companies are critical to ensuring that EV charging is integrated with the energy grid in an efficient manner. That means minimizing costs, improving reliability, and meeting customer needs.

Accelerate the transition to widespread EV adoption

Electric companies are well-positioned to help increase customer awareness about the benefits of EVs. Many electric companies have pursued education and awareness activities, including social media campaigns, community events, and ride-and-drives. Electric companies can leverage their existing relationships with customers to provide information about the benefits of EVs.

Electric companies are leading by example. More than 70 electric companies invested more than $120 million in EVs for their own fleets in 2017 alone. In addition, they have increased the number of EVs in their fleets by 43 percent since 2015. Similarly, electric companies also are incenting their employees to purchase EVs and are providing educational activities to increase awareness in the communities where they live.

Electric companies can help address the lack of charging infrastructure, one of the primary barriers to EV adoption.[16] One major challenge facing greater infrastructure deployment is cost. A customer who wants to install charging equipment today typically must bear all the costs associated with installation, including the charging equipment itself and the infrastructure needed to bring the power to the charging station. Electric companies can help to lower the cost of EV charging infrastructure.

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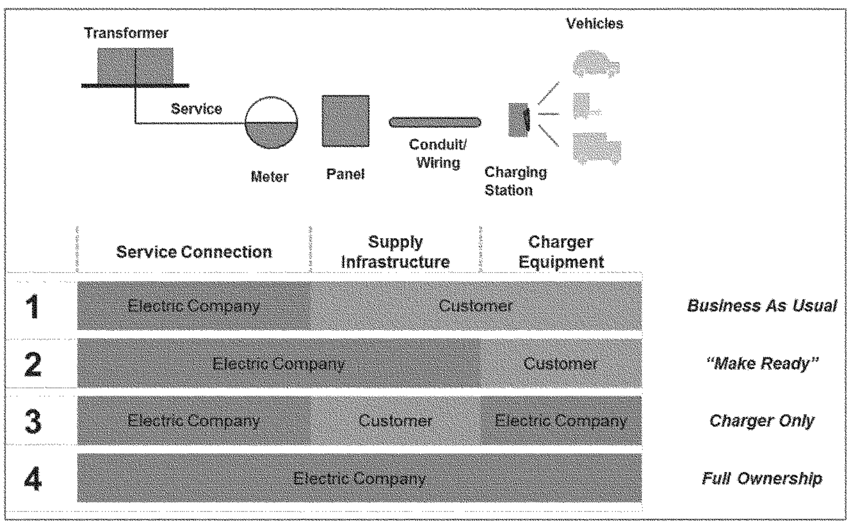
[15] *See, e.g.*, M.J. Bradley & Associates LLC, *Plug-in Electric Vehicle Cost-Benefit Analysis: Maryland* (December 2016), http://mjbradley.com/sites/default/files/MD_PEV_CB_Analysis_FINAL.pdf.

[16] Transportation Research Board and National Research Council, *Overcoming Barriers to Deployment of Plug-in Electric Vehicles* (2015), https://www.nap.edu/catalog/21725/overcoming-barriers-to-deployment-of-plug-in-electric-vehicles.

Electric company charging infrastructure deployment programs can range from providing the basic service connection only (i.e., business as usual) to "full ownership," where the electric company provides the service connection, the supply infrastructure, and the charging equipment (see Figure 4).

1. **Business as Usual.** Electric company funds the distribution upgrades that may be needed to the service connection side.
2. **Make Ready.** Electric company funds the installation and supply infrastructure costs *up to* the charging equipment. The customer procures and pays for the charging equipment.
3. **Charger Only.** Electric company funds and/or owns the charging equipment, utilizing the existing supply infrastructure on the premises and/or offsetting any installation costs.
4. **Full Ownership.** Electric company funds and/or owns the full installation, up to and including the charging equipment.

Figure 4: Electric Company Charging Infrastructure Deployment Options



The flexibility to deploy different approaches is essential because the appropriate approach depends upon the needs of the local market, the type of charging infrastructure, and the customer.

Electric company investments can complement and add to existing activities, such as government- and automaker-funded infrastructure deployment programs and private third-party investment. Electric companies can make investments that are targeted and phased to meet the local market needs. But, electric companies cannot do this alone; multiple market participants will help accelerate the EV market.

In addition to removing barriers to charging infrastructure deployment, the benefits of electric company engagement include:

- **Reliability:** Charging equipment must be maintained. An electric company can maintain equipment that it owns, or it can require regular maintenance of equipment for customers who participate in a program.
- **Affordability:** Electric companies can scale investments, making infrastructure more affordable.
- **Flexible pricing:** Electric companies can provide pricing flexibility for charging station owners, while protecting against unreasonable usage fees.
- **Price signals:** Electric companies can design pricing to encourage specific charging behavior, such as off-peak charging.
- **Customer choice and competition:** Electric companies can provide customers with more options by deploying infrastructure that meets market needs and leverages other investments.
- **Grid integration:** Electric companies can set specification requirements for charging equipment, such as open communication protocols and industry standards that allow the equipment to communicate with the energy grid.

Customers view electric companies as energy experts and expect them to provide information on energy-related technologies and solutions, including EVs. Beyond direct investment in charging infrastructure, electric companies can expand access to charging in a variety of ways, including:

- Electric companies can provide customers with information about their options (as they do today with end-use energy efficiency).
- Electric companies can reduce the costs to customers who install charging equipment by providing unique financing solutions (e.g., on-bill financing) or rebates.

Examples of Electric Company Participation In Charging Infrastructure Deployment

Electric companies are actively engaged in investing in charging infrastructure deployment today. This section provides three examples.

Example #1

Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric

In 2014, the California Public Utilities Commission (CPUC) overturned its 2011 blanket prohibition on electric company-owned EV charging infrastructure. Instead, the CPUC allowed for an expanded electric company role on a case-by-case basis by applying a balancing test that weighs the benefits of electric company ownership of charging infrastructure against any potential impacts to the competitive market.[17] The CPUC recognized that electric companies have a unique role to play in providing and expanding the availability of EV infrastructure, especially in market segments that are harder for third parties to reach, such as low-income communities or multi-unit dwellings.[18]

In response, the state's three major investor-owned electric companies— Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)— proposed pilot programs to install charging infrastructure at multi-unit dwellings, workplaces, and public interest destinations. The three electric company pilots will install the infrastructure to support up to 12,500 charging stations with total budgets of up to $197 million. All three pilots are now in the implementation phase. Each proposal takes a different approach, allowing the state to demonstrate the trade-offs among them.

- PG&E will install "make ready" infrastructure for up to 7,500 Level 2[19] charge ports at multi-unit dwellings and workplaces. Site hosts in multi-unit dwellings and installations in disadvantaged communities can choose to own and maintain the charging equipment themselves or let PG&E own and maintain it (electric company ownership is limited to up to 35 percent of the chargers).
- SCE will install "make ready" infrastructure for up to 1,500 Level 1 and Level 2 charge ports at workplaces, multi-unit dwellings, and other locations where vehicles are parked for extended periods of time.
- SDG&E will install, maintain, and own up to 3,500 Level 1 and Level 2 charge ports at multi-unit dwellings and workplaces, with a special dynamic hourly rate that encourages off-peak charging. SDG&E's ownership and maintenance extend to and include the charging station.

The state legislature took a step further in 2015 with the passage of SB 350, which called upon the CPUC to direct electric companies to propose programs that "accelerate widespread transportation electrification."[20] The subsequent electric company proposals include investing more than $1 billion to

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[17] *See* CPUC Decision 14-12-079, at 5.

[18] Ibid, at 7.

[19] "Level 1" refers to charging on Alternating Current (AC) electricity at 120 volts; "Level 2" refers to charging on AC electricity at 208-240 volts; "DC fast charging" refers to charging on Direct Current (DC) electricity.

[20] *See* California, SB 350, Clean Energy and Pollution Reduction Act of 2015.

support charging infrastructure across a wide range of market segments, including medium- and heavy-duty trucks, DC fast charging, and home-charging solutions, as well as other programs that support transportation electrification.[21]

Example #2

Avista

Washington state passed legislation in 2015 that recognized the need for electric companies to be "fully empowered and incentivized to be engaged in the electrification of our transportation system."[22] In early 2016, Avista filed a proposal for a $3 million pilot program in eastern Washington to install and own 265 Level 2 charging stations at homes, workplaces, fleets, and public locations downstream of the customer meter, as well as seven DC fast charging stations in public locations wholly owned by the electric company from the transformer to the DC fast charger.

Avista's pilot program provides for a comprehensive view of charging behavior utilizing open communications protocols and multiple charging vendors, with remote load management capability. In exchange for the greatly reduced upfront cost of the charging equipment installation and the assurance of the electric company's maintenance and repair of the equipment over its service life, residential and commercial customers agree to allow Avista to collect data and remotely manage EV charging loads, subject to the right to "opt out" of these events without penalty. This will allow the electric company to determine how much peak load from EVs may be shifted to off-peak, while maintaining customer satisfaction and without utilizing a time-of-use rate or other incentives to shift loads.

Avista's filing was debated in open meetings and eventually approved in 2016 by the Washington Utilities and Transportation Commission (WUTC), "recogniz[ing] that the primary purpose of this Pilot Program is to allow Avista to better understand EV charging behavior and the impacts of EV charging on its system, and to promote electric vehicle adoption in Avista's service area consistent with state policy."[23]

Following this, the WUTC initiated further investigation into the policy issues related to electric company investment in charging infrastructure, resulting in policy guidance in 2017 that recognized that electric companies "have a role to play in transforming the market for electric vehicles."[24]

Example #3

Eversource

The Massachusetts Department of Public Utilities (DPU) issued an order in August 2014 that set out the criteria under which an electric company could invest in EV charging infrastructure. Namely, any such proposals must "be in the public interest; meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market; and not hinder the development of the competitive EV charging market."[25]

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21 Fifteen "priority review" projects totaling $43 million were approved in January 2018. See CPUC *Decision on the Transportation Electrification Priority Review Projects* in Application 17-01-020.

22 *See* Washington, HB 1853, Encouraging utility leadership in electric vehicle charging infrastructure build-out.

23 *See* UE-160082, *Order Allowing Tariff Revisions to Become Effective Subject to Conditions.*

24 *See* UE-160799, *Policy and Interpretive Statement Concerning Commission Regulation of Electric Vehicle Charging Services.*

25 *See* Decision 13-182-A (2014).

In January 2017, Eversource Energy proposed a five-year, $45 million program that would install “make ready” infrastructure to support up to 72 DC fast charging ports at 36 locations along travel corridors, and up to 3,955 Level 2 charging ports at 452 locations, including public locations, workplaces, and multi-unit dwellings. The DPU found that the program met its criteria, namely that the program is in the public interest, by “lower[ing] the investment barriers to ownership of the EVSE (electric vehicle supply equipment) [i.e., charger]” and by helping the state meet its goals by “encouraging EV purchases.” In addition, “the program likely will help to boost the market size for the competitive EV charger suppliers,” rather than limiting the competitive market.[26]

Policy Considerations

The benefits of EVs only will be realized if the transition continues to grow and if widespread adoption of EVs occurs. Electric companies can play a critical role in accelerating adoption, but the right policies and regulations need to be in place.

Given the customer, environmental, energy grid, and national security benefits that EVs provide and the critical role that electric companies play in advancing EVs, policies and regulations are needed that:

- Allow electric companies to make investments that support EVs in their communities, including deploying, owning, and operating charging infrastructure, and developing strategies that allow electric companies to manage charging effectively to benefit the customer, the energy grid, and the environment.
- Recognize the critical role of electric companies in educating customers about the benefits of EVs.
- Allow electric companies, where appropriate, to recover costs and earn a reasonable return on EV-related investments, similar to any investment that provides benefits to customers.

Given the importance of charging infrastructure to the development of the EV market, policies are needed that:

- Make charging infrastructure widely available to meet customer needs, including public and private charging for EVs and fleets.
- Support a positive and consistent experience for drivers, charging station owners, and network operators. This means developing an interoperable and open-access system with standards that work regardless of the vehicle type, the equipment type, or the ownership/operation model.
- Require proper monitoring and maintenance to maximize equipment availability, reliability, and safety.

[26] See DPU 17-05, Order Establishing Eversource’s Revenue Requirement.

Conclusion

The benefits of EVs are compelling: reduced emissions, lower costs to customers, more efficient use of the nation's energy grid, and enhanced national security through greater dependence on domestic energy sources. As the adoption of EVs continues to grow nationwide, the role of electric companies in effectively integrating EVs into the energy grid becomes even more critical.

Electric companies can help shape the nation's transition to EVs. As discussed in this paper, electric companies are well-suited to:

- Expand access to EVs to all customers;
- Effectively and efficiently integrate EVs into the energy grid; and
- Jumpstart EV adoption by educating customers and deploying needed EV charging infrastructure.

It is important for policymakers and other stakeholders to leverage the strengths of their electric company partners to help deliver the benefits that widespread adoption of EVs will provide.

The **EDISON ELECTRIC INSTITUTE** (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for about 220 million Americans, and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States. In addition to our U.S. members, EEI has more than 60 international electric companies with operations in more than 90 countries, as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.telligence, and essential conferences and forums.

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Thomas R. Kuhn
President

March 5, 2018

The Honorable Lisa Murkowski
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Senator Murkowski:

We appreciated the opportunity to testify at the Committee's hearing regarding infrastructure on February 8, 2018. During that hearing, there was a discussion about the impact of the mandatory purchase obligation under the Public Utility Regulatory Policies Act of 1978 (PURPA). In light of those inquiries, we wanted to provide additional information to clarify the record about the adverse impact of the PURPA mandatory purchase obligation on electricity customers.

PURPA's mandatory purchase obligation is an outdated policy that has become a tool to stifle competition, resulting in higher energy costs to customers. When the statute was passed forty years ago, renewable energy resources were scarce, electricity demand was growing, and the United States was looking for ways to diversify its energy portfolio. Today's electricity world is vastly different, and PURPA is no longer the key driver for renewable energy development. The growth in renewable energy is being achieved by many other means that are less onerous on consumers, including lower costs of renewable energy resources, federal and state tax incentives, and customers' demand for renewable energy. At a recent meeting of the National Association of Regulatory Utility Commissioners (NARUC), Montana Public Service Commission Vice Chairman Travis Kavulla noted that PURPA as a driver of renewable energy has declined precipitously in recent years.

In today's competitive electricity markets, with the Federal Energy Regulatory Commission's open access requirements and increased competition among generators in organized and bilateral wholesale markets, a utility should not be required to buy renewable energy under PURPA from projects that are not cost-effective and are not acquired through a competitive bidding process. Recent letters submitted to Representative Tim Walberg in support of H.R. 4476, the PURPA Modernization Act of 2017, provided examples of ongoing challenges with PURPA's mandatory purchase obligation:

- Alliant Energy noted that its customers are currently paying $20 million in additional costs under PURPA, and without reforms, customers could potentially pay up to a 50 percent price premium for future QF-generated wind energy in Iowa.
- Consumers Energy stated that PURPA is causing its customers to pay around 30-50 percent over market value for energy provided by QFs. In fact, over 10 years, Consumers Energy customers paid $300 million above market prices to subsidize PURPA facilities.

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- PacifiCorp is currently facing costs of $1.5 billion over the next ten years in excess of projected market prices as a result of contracts mandated under PURPA.
- Duke estimates that in North Carolina alone, retail customers are overpaying by more than $1 billion over the next ten years due to the difference between the actual wholesale price of energy and the avoided cost required by law.
- PGE has 1,575 MW of PURPA contracts either online, under contract or in process. PGE estimates that even if just the approximately 500 MW of currently contracted projects come to fruition, PGE's customers would be forced to pay an estimated $86 million more a year in their power rates by 2022–a 5 percent increase–when these resources will be on line. It could be as high as 15 percent if PGE is required to purchase the output from all PURPA requests to date.
- Idaho Power pointed out that PURPA generation has typically represented approximately only 19 percent of its generation, but 32 percent of its generation costs. Moreover, Idaho Power's all-time peak load is just over 3,400 MW, with system-wide minimum load of approximately 1,100 MW. In comparison Idaho Power has more than 1,130 MW of PURPA generation under long-term contracts currently operating on its system. Idaho Power's long-term integrated resource plan shows that it is completely generation sufficient to meet projected load through the year 2026. However, the mandatory purchase obligation imposed by PURPA requires the continued acquisition of any PURPA project requesting a contract, at prices that typically exceed market prices.

Additionally, at the recent NARUC meeting discussed above, Commissioner Kavulla noted how PURPA payments, following the process established under federal law to set avoided costs, have historically exceeded market costs. In the chart at the end of this letter, the solid dark line shows the standard rates set for NorthWestern Energy's PURPA contracts for wind, and the dotted line shows its solar payments. Both are well above the Northwest market rates, designated as "Mid C" (Mid-Columbia).

We continue to support congressional action to modernize PURPA to reflect the realities of today's electricity markets and provide relief to customers. We look forward to working with you to advance this goal.

Sincerely,

Tom Kuhn

Thomas R. Kuhn

March 2, 2018
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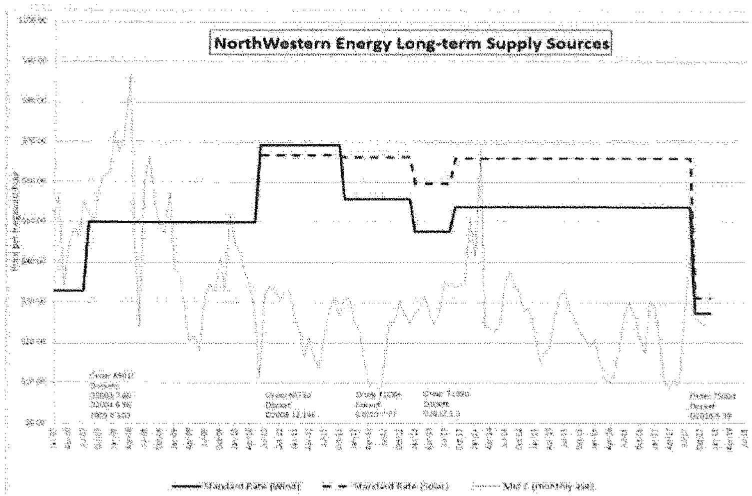

[Exhibit B to Montana Public Service Commission Vice Chairman Travis Kavulla's testimony at the House Energy Subcommittee hearing, "Legislation Addressing LNG Exports and PURPA Modernization," January 19, 2018.]

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Questions from Chairman Lisa Murkowski

Question 1: As we add more internet connected devices to these existing systems, we increase access points for cyber vulnerabilities.

- What safeguards and best practices should be in place as we develop a more interconnected energy delivery system?

  Philip Mezey: Security in our energy infrastructure systems is based on multiple layers of defensive measures. Sometime referred to as defense in depth, other times referred to as a multi-layer defense, this practice or layering security measures is implemented so a compromise of any one device does not impact the larger system. As more devices are connected to one another, layered defense strategies become even more important.

  Some safeguards and best practices implemented in a multi-layered defense include:
    - Secure design principles.
    - Secure software development practices.
    - Secure firmware and configuration loading.
    - Robust and resilient deployments (where one device failure does not impact other systems).

  We are deploying these methods in our industry today. As new use cases for energy delivery emerge—driving the development of new devices—we must continue to implement the best available, vetted and accepted methods to achieve robust security between connected devices.

- Is the federal government doing enough to ensure security?

  Philip Mezey: The federal government has a crucial role to play in evaluating and vetting security technologies. The work at NIST with the federal information processing standards (FIPS) in an excellent example.

  We in the industry—both vendors such as Itron and the utilities we serve—rely on the FIPS standards to be authoritative, well-studied and proven. It takes an impartial convener like the federal government to bring all the stakeholders to the table.

  As technology continues to evolve at a dizzying pace, more devices become connected, and almost everything we do and depend on becomes software-driven, there will be new attack vectors and threats that were not present even a few years ago. Government sponsorship to identify and study these new threats will help move the industry forward and ensure we develop new best practices and standards.

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- Can the private sector do a better job with ensuring security?

  Philip Mezey: The private sector can do more. A significant point to consider with an interconnected energy delivery system is the dependency of everyone on energy delivery—from the end consumers and governments (local, state and federal) to the utilities providing the service and the vendors providing the equipment. While each of these constituents are contributing within their space, we really can't say we are fully collaborating. For the private sector to do more, we need the federal government to remain committed to bringing all vested stakeholders to an impartial table.

  In the private sector, we are fine-tuning our own processes to continue to build trust in our equipment, and we will adopt new best practices as they evolve. We also have a vested interest in identifying cost-effective and easy-to-implement technologies. Our utility customers are not served well if the security technology offered by vendors is operationally complex or cost prohibitive.

Question 2: Unfortunately, our nation has experienced a number of devastating natural disasters over the past twelve months. You mention a good news story about CenterPoint Energy using advanced metering infrastructure technology to bring customers online faster in the wake of Hurricane Harvey.

- As Puerto Rico looks to rebuild following Hurricanes Irma and Maria, is there a role for this sort of advanced metering infrastructure?

  Philip Mezey: Absolutely.

- How could it help places like Puerto Rico and other hurricane prone areas to recover in the wake of a disaster?

  Philip Mezey: By using smart energy infrastructure, with intelligence embedded all the way to the edge of the network, utilities can better pinpoint exactly what equipment is offline and where. For electricity providers, smart devices better define the extents of an outage and can even identify transformers and other primary equipment that have been damaged. For gas providers, smart devices can identify where leaks are occurring and remotely disconnect service, remedying a potentially disastrous situation. This takes much of the guesswork out of relief efforts and allows crews to spend their time on the most important tasks of ensuring safety, restoring power and cleaning up hazards throughout their distribution systems.

- Would it be worth the extra cost of installing such a system?

  Philip Mezey: Yes. According to a GAO report on natural hazard mitigation (2007), for every $1 FEMA spends on prevention, it saves $4 in restoration costs. Investments in

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smart grid technology not only make our utilities more efficient in their operations, but also make them more resilient in the face of natural disasters. In addition to speeding recovery after hurricanes such as Harvey, Irma, Maria and others, demand response and energy efficiency investments will help maintain grid reliability and stability during times of extreme heat, avoiding the system-wide black-outs or rolling brown-outs that have been experienced in the past.

Smart technology embedded in our water infrastructure can also:

- Preserve water by proactively detecting leaks within the distribution system, ensuring that resources are not needlessly wasted in times of drought.
- Monitor pressure, temperature, water quality and more through a variety of sensors that can be inserted throughout the distribution system.
- Identify potential hazards during recovery efforts after a natural disaster.
- Increase consumer engagement and awareness to help better manage this most vital resource.

Smart technology can help make our Nation's electricity, gas and water systems more resilient and reliable. And with military-grade security applied within this technology and across the system, we can also harden our critical infrastructure against cyber threats from foreign actors.

- Do you have methods for making this cost/benefit calculation?

  Philip Mezey: Yes, there are a variety of standardized cost/benefit methodologies employed by state public service commissions (PSC) across the nation. These are used to determine the public benefits of all capital investments made by regulated utilities before being added to the rate base. In most cases, PSC commissions only authorize investments where the public benefits exceed the costs.

Question from Senator Ron Wyden

Question: Hurricanes Maria and Irma reminded us of the vulnerability of our critical energy infrastructure to natural disasters. I want to make sure that steps are being taken to protect Oregonians from the impacts of a disaster such as an earthquake in the Cascadia subduction zone.

Last September, I introduced three bills (S.1874, S,1875 and S.1876) to increase the flexibility and resiliency of our grid. These bills authorize Department of Energy programs that would reduce the cost of energy storage, fund distributed energy technologies like smart water heaters, and demonstrate new technologies to balance the grid.

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How could increased grid flexibility help in the aftermath of a disaster such as a large earthquake?

Philip Mezey: All of the activities described above would greatly help grid flexibility, resiliency and recovery after a natural disaster like an earthquake. The intelligence embedded in smart devices, operating on the edge of the network, help utilities better pinpoint exactly what equipment is offline and where. This takes much of the guesswork out of relief efforts and allows crews to spend their time on the most important tasks of ensuring safety, restoring power and cleaning up hazards throughout their distribution systems.

Investing in—and demonstrating the value of—grid technologies like batteries and storage is an important piece of the puzzle as well. With better local storage of energy and the integration of distributed energy resources (DERs) like wind and solar, microgrids can be established that could supplement our traditional power grid in times of crisis (natural disasters and times of excessive demand). With a healthy ecosystem of microgrids, repairs and maintenance of the main, traditional power grid can be less disruptive to consumers.

Questions from Senator Debbie Stabenow

Questions: As my colleagues and I on this Committee examine opportunities and challenges to building new energy systems, we have paid special attention to cybersecurity.

In your written testimony, you share your company's involvement in developing smart cities with connected energy, water, and waste systems.

As we increase interconnectedness in critical infrastructure, how can we ensure these networks are protected from cyber threats? That is, how can we connect and protect at the same time?

Philip Mezey: The key to security in our energy infrastructure systems ensuring we have multiple layers of defensive measures in place. Sometime referred to as defense in depth, other times referred to as a multi-layer defense, this practice or layering security measures is implemented so a compromise of any one device does not impact the larger system. As more devices are connected to one another, layered defense strategies become even more important.

Some safeguards and best practices implemented in a multi-layered defense include:

- Secure design principles.
- Secure software development practices.
- Secure firmware and configuration loading.
- Robust and resilient deployments (where one device failure does not impact other systems).

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We are deploying these methods in our industry today. As new use cases for energy delivery emerge—driving the development of new devices—we must continue to implement the best available, vetted and accepted methods to achieve robust security between connected devices.

The federal government has a crucial role to play in evaluating and vetting security technologies. The work at NIST with the federal information processing standards (FIPS) in an excellent example.

We in the industry—both vendors such as Itron and the utilities we serve—rely on the FIPS standards to be authoritative, well-studied and proven. It takes an impartial convener like the federal government to bring all the stakeholders to the table.

Questions from Senator Joe Manchin, III

Question 1: The decline of the coal industry has been devastating to my home state. We lost businesses and population. So we are looking for ways to revitalize our home state economy. I have been working for some time with Senator Capito to bring stakeholders together to help realize the potential of an Appalachian Storage Hub – an innovative energy infrastructure project that will attract manufacturing investment and create jobs. Our area is primed for this sort of energy project because of our abundant natural gas, natural gas liquids and natural geologic storage. This is exactly the type of effort is what Congress envisioned when it created the Title Seventeen loan program. The Loan Program Office (LPO) helps provide low cost capital to innovative energy projects in order to help alleviate investor concerns and get the project into development. The future of this program is currently in question though. So I'm concerned that Congress is going to unwittingly tie the hands of many energy infrastructure projects – not just this one – if we don't ensure this program is funded going forward.

As you reviewed the evolution of energy infrastructure in this country, do you believe the US government has had a role in innovating us to the next stage?

Is it fair to say that the loan program has had a profound impact on the evolution of how electricity is produced and delivered in this country today?

Philip Mezey: Through technology and strategic investment, there are tremendous opportunities—available today—to make our nation's electric, gas and water systems more efficient and to meet the increasingly demanding needs of customers. We are developing and deploying technology that allows utilities and vendors alike to drive innovation, to better understand and leverage big data, and to help consumers better understand their use and change behaviors—all to make sure we get the most of our electricity, gas and water resources.

Investments in intelligent appliances, integration tools and smart cities today will all help us use this technology to its fullest potential. Although a key piece of the innovation pipeline, private

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industry alone cannot adopt or fund at the levels necessary to meet the demands of a changing market and expectant consumer. Partnering with the federal government and securing federal incentives—including those available to the Loan Guarantee program or regulatory certainty in appropriate circumstances—will help technology vendors like Itron, our utility and city partners continue systematic innovation.

Question 2: On January 28, the Washington Post reported that a tanker carrying liquefied natural gas (LNG) from Russia arrived in Boston Harbor. That tanker had gas on it from the Yamal facility – a project largely financed by the Russian company Novatek. In July of 2014, after Russia annexed Crimea, the US Treasury Department issued sanctions that were specifically targeted at weakening the Russian energy sector – those sanctions forbid any financing for projects belonging to Novatek. Recognizing Boston was not its first step along the journey, it seems though that these sanctions do not prohibit the purchase of gas from this Russian project in the Arctic. So – in short – there is Russian LNG being turned back into gas at one of our ports and then being used to power American homes. Earlier this week, the Energy Information Administration released its Annual Energy Outlook for 2018. In the Reference case, natural gas production accounts for the largest share of total energy production - 39% by 2050. That's domestic fuel.

My question is simple: Why, when we have one of the world's greatest reserves of natural gas sitting right under West Virginia, are we importing it at the risk of bolstering Russia's energy sector?

Philip Mezey: As a technology and services provider, we are not involved in choosing the types of fuel used for generation. We are focused on increasing connectivity, rethinking the paradigm of how we collect and use data and making the key, strategic investments today to help us and our industry transform for the future. I believe that focusing on improving water and energy efficiencies is an investment in economic vitality—and this where Itron can be a leader and strategic partner for communities around the country.

Questions from Senator Catherine Cortez Masto

Question 1: What alternatives can the federal government consider to encourage growth and local project development rather than walking back regulations more broadly?

Philip Mezey: Local needs are the primary factor when looking at the utility infrastructure that brings water, electricity and gas to the homes, businesses and industries around the U.S. And the state and local planners and regulators should be the most informed stakeholders when making decisions that impact these needs.

Unfortunately, investments that would bring innovation, economic development and improvements in service, safety, cost and modernization of legacy systems are not always selected, for a variety of reasons:

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- State and local regulations may need to be reformed to consider the new realities of an electric delivery system which provides for the two-way flow of electricity.
- State public utility commissions may be constrained by 100 year-old economic regulatory models, which do not encourage innovation.
- The way investments in utility systems are considered and approved can slow adoption of even the most robust and desirable innovations.

Leak detection in both water and gas systems are available today—as are options like pressure and temperature monitoring (water), and methane sensing and cathodic protection (gas). Robust, remote electricity outage detection is available today. Integration of distributed energy resources (DERs) is available today. And our ability to utilize the massive efficiencies of linking technologies and the supply of our urban, rural and suburban with needed water and power—as well as other critical service, necessities and amenities—are all available today.

The federal government can help by:

- Asking the private sector to promote and publicize the many opportunities available.
- Assist state and local governments as they learn about and fund these efforts.
- Communicate and disseminate information about best practices and real, on the ground results.

Investments like these will pay enormous dividends in every sector.

Question 2: Mr. Allen spoke about the need to invest in rural areas and you spoke of investing in smart technologies in cities. How can we bridge that divide to utilize those technologies and make them accessible to all communities?

Philip Mezey: Smart cities are a focus of some of Itron's activities—but not exclusively and not at the exception of deploying innovative technologies that work well and boost economies in rural areas. Smart cities are typically fast adopters and great proving-ground of this smart infrastructure technology for several reasons:

- Utility providers within cities are typically well-known to one another and have the relationships in place to partner on joint developments.
- A foundational component to a smart city is a network that unifies a variety of devices underneath it. Whether it be from streetlights or metered electricity/gas/water connection points, cities have infrastructure in place that is ideal to layer a network over the top of—allowing for cost-effective deployment of the network.
- Smart city drivers move beyond traditional utility use cases and help fuel innovation that can be proven and then applied outside the city.

Some of the greatest innovators in our industry are this nation's rural electric co-ops, who own and maintain 2.6 million miles (or 42%) of the nation's electricity distribution lines. Over the last seven years, numerous solar projects have been developed by co-ops in Colorado, Utah and Michigan, taking renewable energy technology outside the city. Itron customer Texas-New

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Mexico Power, which has 40% of its customers in rural areas, has deployed a cellular solution to effectively connect and collect data from its network.

In order to bridge the divide between smart city and smart community, we need to continue to develop and validate technologies, software and services within the city space, and then leverage our experience to expand it to rural areas. Some benefits of smart infrastructure—such as outage and leak detection—are already available today in rural communities.

Question 3: What prohibits more communities from utilizing these energy efficiency technologies and how can Congress help to remove those barriers? Is there a reason why more cities aren't more widely utilizing these technologies?

Philip Mezey: Investments in water, and gas and electric systems are just that—investments. Our customers want to be certain that, when they are buying new systems and installing smart devices at homes and businesses, they are making an investment that will bring quantifiable and long-lasting benefits.

We meet those expectations with technology solutions engineered to work reliably and at scale in some of the harshest environments imaginable for years and even decades. Our technology meets diverse needs and works well virtually anywhere.

The challenge for us is to get in front of our industry, customers and communities to demonstrate the potential of smart technology. This is our company's mission and work. We are advocating for more integration of smart technologies, and more collaboration and coordination between (and among) different policy goals and infrastructure needs.

We stand ready to participate in any discussions and consider any policies that will advance the tools and technologies needed to ensure the safe, reliable and resilient delivery of energy and water throughout the U.S.

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Questions from Chairman Lisa Murkowski

Question 1: In your testimony, you discussed the need for reform of the federal siting and licensing process for both transmission lines and hydropower.

- What reforms would you suggest that would remove these barriers to energy infrastructure projects moving forward and securing the necessary capital investment?

Answer: Regarding hydropower, the Department of Energy (DOE) estimates that there is close to 50 GW of new hydropower capacity that could be reasonably developed by 2050, and even more available through marine energy and hydrokinetic sources. In addition, there is a massive need for reinvestment in the existing aging hydroelectric fleet. In the next 15 years, the licenses for over 500 hydroelectric projects will expire and require renewal by the Federal Energy Regulatory Commission (FERC). In order to maintain and grow the clean, baseload power provided by hydropower, key barriers must be addressed.

Steve Wright, General Manager of LPPC member Chelan County Public Utility District No. 1, testified in October of 2017 before the House Energy and Commerce Committee (Subcommittee on Energy) that the hydroelectric relicensing process can take 10 years or more to complete, with process costs representing a significant portion of a licensee's overall costs to obtain and implement a 30-50 year license. Furthermore, costs and delays associated with hydropower licensing can affect the timing and level of ongoing investments. The operational flexibility of hydropower facilities – which contributes significantly to system reliability – is often limited by conditions required to obtain a new license. Under your leadership, key provisions advanced by the Senate in S. 1460 will implement needed regulatory improvements to the licensing process that will result in significant benefits for hydropower infrastructure. We urge Congress to advance these reforms.

With respect to electric transmission infrastructure, while siting authority is generally exercised by state and municipal authorities, federal agencies are involved where federal lands are implicated, and in cases where, for instance, endangered species or wetlands may be affected. In these cases, multi-year review processes can substantially delay needed infrastructure and may involve conflicting determinations regarding acceptable routes.

Through a Presidential Memorandum issued on June 7, 2013, "Transforming Our Nation's Electric Grid through Improved Siting, Permitting, and Review" 78 Fed. Reg. 35539 (June 12, 2013), the previous administration directed DOE to establish an inter-agency pre-application process designed to facilitate the coordination of review for proposed projects at both the federal and state levels. DOE published the resulting regulations in November 2016

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(https://www.energy. gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/improving).

Though a commendable effort, the voluntary DOE process does not ensure that decisions can be made within commercially reasonable time frames. Where federal permitting authority is involved, we believe Congress should take steps to establish clear deadlines for all affected federal agencies, to remove uncertainty for these agencies and for developers of energy infrastructure as to precisely when affirmative agency action must be taken. Establishing a firm deadline for action of between 12 and 18 months would provide federal agencies with a reasonable amount of time within which to act, while also imposing some discipline on the siting process.

- Does Congress need to be involved, or is this a matter of better cooperation between all the federal and state agencies? If you think Congress should be involved, how?

Answer: LPPC believes that Congress can play a constructive role, as indicated above, with respect to reform of hydropower licensing procedures, and in connection with the imposition of commercially reasonable time frames for the resolution of federal agency decisions affecting electric transmission siting.

Question 2: You discuss some specific problems experienced by public power in the design of the 2009 stimulus package --- specifically, the "Build America Bonds." In particular, you mention that tax credits are not accessible to public power entities unless they engage with a tax-paying counter-party, which creates inefficiencies. You also mention that IRS private use restrictions have not been updated since 1986.

- Has the IRS expressed any willingness to look at these issues?
- Is there still a need for "Build America Bonds?" If so, for what type of projects?

Answer:

Tax credits. As indicated, public power entities are not able to access tax credits for renewable energy directly and, instead, must use power purchase agreements ("PPAs") with taxpaying counterparties to achieve some of the benefit of the tax credits. These PPA structures are inefficient in that the taxpaying entity receives some of the value of the subsidy and, as a result, that portion of the subsidy is not funding the cost of the renewable energy assets for which the credits were enacted. In addition, the need to use these PPA structures results in the public power entity being unable to own the asset except through a purchase at fair market value at the end of the tax credit period. LPPC and its members have long sought a comparable incentive for

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renewables that could be accessed by public power entities directly. The American Recovery and Reinvestment Act of 2009 created the now-expired section 1603 grant program that could be used in lieu of tax credits to obtain assistance in funding renewable energy projects but this program was also not directly available to public power. The "clean renewable energy bond" (or "CREB") program was created to provide direct, comparable assistance to public power but this program was capped at levels that made it wholly inadequate and, moreover, was eliminated in the recent tax law changes along with other tax credit bonds.

<u>Private use restrictions</u>. The private use rules significantly impact the day-to-day operations of public power entities by restricting public power's ability to do business with nongovernmental entities, including investor owned utilities and, in some circumstances, their own customers. As you state, the private use rules have not been updated in many years: the Internal Revenue Code provisions were enacted in 1986 and have not been updated since then. The applicable IRS regulations interpreting those Code provisions were last updated in 2002. Some of these restrictions, such as the Code prohibition on private use of a project in excess of $15 million, were overly restrictive 30 years ago and have become even more problematic given inflation over that period. Other restrictions in the Code and regulations have not taken into account the dramatic changes in the industry over that period. As an example, public power systems could lose their largest existing customers and be unable to compete for large, new customers because of the private use rules. While some of these issues could be dealt with by the IRS, others would require Congressional action.

<u>Build America Bonds</u>. LPPC supports the re-enactment of Build America Bonds (BABs) to complement the existing tax-exempt bond market and, as in the stimulus package version, we suggest that all issuers of tax-exempt "governmental bonds" (that is, bonds other than private activity bonds) be permitted to issue BABs. By providing State and local governments with the ability to issue taxable bonds that were supported by direct payments to the issuers, BABs enabled these bond issuers to access investors in the taxable bond market who do not necessarily invest in tax-exempt bonds (for example, pension funds and foreign investors) and increased potential demand for municipal bonds beyond the tax-exempt bond market. In particular, taxable bond investors are generally more interested in the long-term bonds that public power systems prefer to issue, as compared to tax-exempt bond investors. The BABs program also increased the efficiency of tax-exempt bonds, both for issuers of tax-exempt bonds and the federal government: if the interest savings from tax-exempt bonds are not as substantial as they should be, State and local governments issued BABs instead. By issuing BABs in these circumstances, issuers were able to minimize their financing costs and also increase demand for tax-exempt bonds to reduce their rates. If a BABs program is re-enacted, it is important that these bonds are exempted from sequestration. Not only has sequestration retroactively reduced the subsidy payments that State and local governments were entitled to under the stimulus act, but it would also make those entities reluctant to issue BABs in the future.

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Questions from Senator Joe Manchin, III

Question 1: The decline of the coal industry has been devastating to my home state. We lost businesses and population. So we are looking for ways to revitalize our home state economy. I have been working for some time with Senator Capito to bring stakeholders together to help realize the potential of an Appalachian Storage Hub – an innovative energy infrastructure project that will attract manufacturing investment and create jobs. Our area is primed for this sort of energy project because of our abundant natural gas, natural gas liquids and natural geologic storage. This is exactly the type of effort is what Congress envisioned when it created the Title Seventeen loan program. The Loan Program Office (LPO) helps provide low cost capital to innovative energy projects in order to help alleviate investor concerns and get the project into development. The future of this program is currently in question though. So I'm concerned that Congress is going to unwittingly tie the hands of many energy infrastructure projects – not just this one – if we don't ensure this program is funded going forward.

As you reviewed the evolution of energy infrastructure in this country, do you believe the US government has had a role in innovating us to the next stage?

Is it fair to say that the loan program has had a profound impact on the evolution of how electricity is produced and delivered in this country today?

Answer: The federal government plays a critical role in supporting and advancing energy technology innovation and the Loan Programs Office has driven significant investments in the electric sector. LPPC strongly supports federal encouragement for investments in innovative technologies in the electric sector.

Federal support for technology innovation should not, however, drift into mandates to use particular technologies. The electric industry performs best when asked to meet broad objectives, empowering individual utilities to determine how best to meet public policy goals given regional differences, existing infrastructure and state policy objectives.

Question 2: On January 28, the Washington Post reported that a tanker carrying liquefied natural gas (LNG) from Russia arrived in Boston Harbor. That tanker had gas on it from the Yamal facility – a project largely financed by the Russian company Novatek. In July of 2014, after Russia annexed Crimea, the US Treasury Department issued sanctions that were specifically targeted at weakening the Russian energy sector – those sanctions forbid any financing for projects belonging to Novatek. Recognizing Boston was not its first step along the journey, it seems though that these sanctions do not prohibit the purchase of gas from this Russian project in the Arctic. So – in short – there is Russian LNG being turned back into gas at

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one of our ports and then being used to power American homes. Earlier this week, the Energy Information Administration released its Annual Energy Outlook for 2018. In the Reference case, natural gas production accounts for the largest share of total energy production - 39% by 2050. That's domestic fuel.

My question is simple: Why, when we have one of the world's greatest reserves of natural gas sitting right under West Virginia, are we importing it at the risk of bolstering Russia's energy sector?

Answer: Our member utilities rely on diverse resources to meet their generation needs, including domestic natural gas, domestic coal, nuclear, hydropower and other renewables, to provide reliable, affordable electricity service to the communities which we serve. LPPC would be interested in exploring policies that are aimed at supporting further development of domestic energy resources consistent with our goals of providing reliable, low-cost energy.

Question 3: In October of last year, your organization along with a handful of others wrote to the Senate to express the need for legislation that provides a stronger framework for vegetation management and other types of maintenance of electric infrastructure on federal lands. The letter stated that "Managing vegetation on electric transmission and distribution rights-of-way is a key part of electric company efforts to protect the security and reliability of the energy grid." It also can help reduce wildfire risk, thereby increasing public safety and worker safety. I've heard from numerous stakeholders about the challenges associated with vegetation management on federal land and the primary complaint is that it can be very difficult to get timely approval to implement and execute vegetation management plans, some of which are routine operation and maintenance activities, on federal lands. Such lack of action within the agencies has resulted in electric utility work delays and stoppages on federal lands - often due to a variety of factors, including narrow and inconsistent interpretations of NEPA related to tree removal and other activities on the corridor.

How much of vegetation management is routine maintenance?

Is there a risk that these delays have reached a point where they are causing unnecessary hazards to life, natural resources, and property, as well as power outages?

Is there a cost to electric utility customers when these rights of way are not appropriately maintained?

Answer: The safety and reliability of our electric grid is of paramount importance to LPPC member utilities. Vegetation management is an integral part of our reliability efforts. Each utility with right-of-way crossing federal land develops and implements a vegetation management plan

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which complies with the requirements of the Federal Land Policy and Management Act and the applicable Reliability Standards established by NERC. If obtaining required federal land management agency approvals causes delay in needed vegetation management activities, service outages and wildfires can result.

We support passage of H.R. 1873, the Electricity Reliability and Forest Protection Act and the inclusion of provisions to improve federal policies impacting vegetation management in S. 1460, the Energy and Natural Resources Act of 2017, to address these bureaucratic obstacles. Implementation of the changes will establish a better framework to promote consistency in federal land management, accountability, and timely decision-making as it relates to protecting power lines on federal lands and reducing the risk of wildfires.

Questions from Senator Catherine Cortez Masto

Question 1: My state is a big proponent of battery technology. We are home to a large battery factory (Tesla Gigafactory) and Nevada recently created an "Energy Bill of Rights" that protects home energy generation and storage. Thanks to declining costs, better technological, and a growing industry, battery storage deployment at a utility-scale is accelerating at a rapid pace.

- How can the U.S. be a leader in utilizing this technology, and in so doing increasing grid reliability and clean energy while reducing costs to the ratepayer?
- What barriers exist for battery storage deployment and how can the government address those barriers?

Answer: Storage technologies have advanced considerably in both cost and performance. Going forward, they will have an important place in the United States energy grid to help integrate and regulate intermittent renewables and to balance variable loads. The United States is leading in the development and deployment of many of these technologies and will continue to do so as market conditions support the adoption of both utility scale and distributed storage.

A recent FERC decision in Docket No. RM16-23 has provided a boost for these resources, with the Commission requiring each RTO/ISO to revise its tariffs in order to enable electric storage resources, including batteries interconnected at the distribution level and behind utility meters, to participate in all FERC regulated capacity, energy and ancillary service markets in which they are capable of providing service.

The decision to enable smaller scale storage resources to participate in wholesale markets on the same basis as central station generating resources creates a large market platform to monetize the capabilities of these technologies going forward.

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There are also several states which are supporting battery storage technology initiatives prompting utilities to solicit significant numbers of requests for proposals for storage technologies of many different types. New York, California, Arizona and Georgia, to name a few, have taken these steps. Recent solicitations are no longer for R&D pilot projects, but rather are the size of other resource acquisitions. Within LPPC, a number of member utilities are evaluating and securing storage technologies, including batteries, based on how they best complement the existing resource mix, consumer interests and regional supply differences.

Since many of these technologies continue to be in the developmental stage, LPPC also urges the federal government to support R&D into evolving new storage technologies to assist in their commercialization.

Question 2: As we look at the evolution of our nation's energy infrastructure, I think it is important to factor into that equation the linkage between energy production and water usage. This is particularly important to a western state like mine where we are water challenged. How do you factor in the availability of water when you make decisions about citing power generation facilities?

Answer: Energy and water are significantly linked and states, in their role in siting power plants, are increasingly considering water efficiency and the use of ambient versus water cooling as a matter of permitting review. The use of reclaimed water has also become a very important factor in power plant cooling. In the West, a significant amount of electricity is used to facilitate the movement of water. In California it is one of the single largest uses of electricity. As Congress considers support for upgrading the Nation's infrastructure, the interdependence of water, electricity and natural gas infrastructure becomes a key aspect of the ability to create efficiencies and conserve resources. Careful coordination and recognition of regional differences is a key to continuing the work that has been done in this area.

Question 3: How do you factor in the impact these facilities will have on future water supply and reserves and the impact this will have on other local water that is available for consumers?

Answer: When new facilities go through permitting their impact on water and other resources are carefully considered. This is a critical aspect of permitting or licensing of facilities like hydro-electric projects, where consumptive rights for municipal uses are considered as well as biological and other environmental impacts.

Question 4: How are you compensating for changes in water availability and the potential declining supply of water as you make decisions about building future energy production facilities?

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Answer: All resource planning for new resources and assessments of the long-term performance of existing resources consider changing hydrography. There are very significant resources and data available that have captured changes in the historical supply of water, both in volume and timing, and extensive modeling has occurred to project water supply into the future. These aspects of changing water supplies and the associated risks are factored into every resource decision as an essential element, recognizing some very significant regional differences.

Question 5: Regarding wildfire, do you factor in the current and future risks associated with the placement of these transmission lines to include the increased risk of wildfire, especially as our arid regions of the west become warmer and drier?

Answer: LPPC members are committed to the safety and reliability of our electric grid. Environmental impacts are an important factor in siting of new transmission lines. Regarding the maintenance of existing lines, vegetation management is an integral part of our reliability efforts. LPPC has supported provisions included in S. 1460 and H.R. 1873 that greatly improve federal policies impacting vegetation management on federal lands and we urge Congress to adopt these provisions.

Question 6: We are on the cusp of a global electric vehicle boom. Almost every major automaker has announced plans to significantly shift their focus from internal combustion engines to electric in the next few years if they haven't already. Can you discuss how utilities are approaching the impending load growth as a result of increased EV deployment? Do you also see this as a major opportunity?

Answer: We are actively working with a wide range of stakeholders in the transition to growing use of electric transportation for personal vehicles, fleets, and industrial and port electrification. The availability, and standardization, of charging infrastructure is very important to allow consumers the greatest number of charging options. Some uniformity of pricing models will also be an important consideration to create transparency for consumers. Utilities see electrification of transportation as a great opportunity to improve the environment through lowering vehicle emissions and improving air quality.

Question 7: Has the utility industry thought about how it can be leading deployment of charging infrastructure in corridors to meet the needs of increasing EV penetration?

Answer: Since the vast majority of charging occurs at home and at the workplace, the remaining charging along corridors and at other transportation hubs such as airports, rail and light rail terminals deserve a deeper focus. Many highway corridors, especially in rural areas, do not have significant electric loads so the infrastructure available may not be adequate to support fast charging of electric vehicles. This is an area where federal financial support in the form of grants or loans could be beneficial to support the build out of this infrastructure.

Question 8: How can the utility industry assist in ensuring EV operators in urban environments, multi-unit dwellings, and rentals can have reliable access to home charging, where the vast majority of charging happens?

Answer: Many of our member utilities serve urban environments and assist with workplace, multi-family and public charging, consistent with the transportation and planning policies of the municipalities they serve in cities including Los Angeles, Sacramento, Seattle, Austin and Phoenix.

Question 9: I have been working to garner the support of various entities for my legislation called the Moving FIRST Act. This bill reinitiates the DOTs smart cities challenges to create more opportunities for communities of all sizes to work with private partners to collaborate and address individual challenges that communities large and small want to address. That includes the continued expansion of electric vehicles, which is a fundamental element of the kind of applications I hope this grant challenge will address – to increase energy efficiency and reduce the transportation sector's carbon footprint. Do you think this is a concept your members would find of interest or support?

Answer: We have been very supportive of the expansion of electric vehicles to improve both efficiency and environmental outcomes. We have been looking at ways to ensure that clean air regulation, which currently addresses vehicle emissions and electricity generation emissions separately, does not act as an obstacle to electric vehicle adoption. Instead, the reduction in vehicle emissions resulting from electric vehicle adoption should be a consideration in regulation of potentially increased electric sector generation needed to power the growing electric vehicle fleet. We are working with the EPA as well as state air regulators to look for ways to remove this barrier. The efficiency and cost-effectiveness of air quality improvements and GHG emission reductions can be improved through a cross sector approach. I, along with several of our members including the New York Power Authority and Sacramento Municipal Utility District, are participating in the Alliance to Save Energy's "50 by 50 Transportation Commission." The group comprised of business, government and civic society leaders are working together to develop a pathway and recommendations to reduce energy use in the transportation sector by 50 percent by 2050 while meeting future mobility needs.

Question 10: Are you able to be flexible enough to work with local jurisdictions to help them improve their transportation or energy sectors with support from the federal government?

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Answer: Yes. Our member utilities are part of municipal governments, or serve municipalities as partner public organizations, and/or serve municipalities as wholesaler suppliers. In each case, LPPC members are relied upon as a partner in achieving the economic and environmental goals being sought within our communities and regions.

Question 11: In addition to EVs, what other technologies do you see being promoted for the smart communities that are cropping up throughout the country?

Answer: Advanced metering has created a digital communications platform to allow for two-way communications between utilities and devices creating more interoperability and transparency for consumers. With these technology platforms in place across much of the nation, the next focus is the deployment of advanced distribution management systems – systems that not only manage the utility network as a delivery system but manage a broader ecosystem and network for the integration and interoperability of distributed energy, storage, electric vehicles, traditional resources and control hardware. The use of data analytics and predictive machine learning promises greater integration and resilience of these critical systems.

Question 12: So much of our infrastructure is built by our local governments, including municipalities and public utility districts. How can we make sure that public-private partnerships keep local governments involved with decision-making without transferring to them the bulk of financing responsibility?

Answer: This is a matter of critical importance for our members. Collectively we have invested billions of dollars on critical public purpose infrastructure over the past decade and much of our country's infrastructure has been financed using municipal bonds. To ensure that we maintain our ability to invest in our communities as municipal debt issuers, we need to maintain the current tax-exemption for interest on municipal bonds.

Further, the private use rules significantly impact the day-to-day operations of public power entities by restricting public power's ability to do business with nongovernmental entities, including investor owned utilities and, in some circumstances, their own customers. The private use rules have not been updated in many years: the Internal Revenue Code provisions were enacted in 1986 and have not been updated since then. The applicable IRS regulations interpreting those Code provisions were last updated in 2002. Some of these restrictions, such as the Code prohibition on private use of a project in excess of $15 million, were overly restrictive 30 years ago and have become even more problematic given inflation over that period. Other restrictions in the Code and regulations have not taken into account the dramatic changes in the industry over that period. As an example, public power systems could lose their largest existing customers and be unable to compete for large, new customers because of the private use rules. While some of these issues could be dealt with by the IRS, others would require Congressional action.

Any tax incentives provided by the federal government for utility-related infrastructure investments should include policies to provide comparable direct incentives for public power systems. Incentives provided through the tax code are not accessible to government entities such as LPPC members. Instead, we can access such incentives only through contracting with a tax-paying counter-party, thus diluting the benefit to our communities and limiting the size of investments.

Direct pay bonds such as the now-expired Build America Bonds were widely used by our members and worked very well, but need to be protected against sequestration for the life of the issuance should they be reauthorized.

Finally, we note that the type of public-private partnerships where State or local governments fund infrastructure projects by entering into long-term leases or concession agreements for projects with private entities (e.g., privately developed toll road projects), which the Administration seems to be encouraging, have not been used in the energy area. We believe that it is important that infrastructure investment policies to encourage other types of cooperative efforts between public power and private entities that are appropriate to the energy sector.

Question 13: Energy infrastructure can sometimes contribute to local economies even more directly than transportation 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: The federal government can be very helpful in establishing clear, high level, policies that reflect critical national objectives such as security, resilience, reliability, environmental performance and economic vitality. If the federal government has clarity on the key overarching national objectives and supports those areas through its policies, the energy sector can invest to align regional and local actions to broader national objectives.

Congress has an opportunity to ensure that any infrastructure packages that emerge include public power infrastructure investment projects. In addition, as indicated above, updates to the private use rules would facilitate investment in situations where public power can work with other industry participants. We would be happy to work with you on these approaches.

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[No responses were received as of the date of printing.]

Questions from Chairman Lisa Murkowski

Question 1: Smart-grid demonstration projects, exploring the need for Internet of Things and interconnected smart buildings and energy systems can all be effective at reducing wasteful energy uses.

- How can we most effectively and efficiently adopt these types of advances and innovations in energy efficiency to our most isolated, remote communities?

Question 2: You discuss "conservation over consumption", specifically, a recent analysis by a group of Oregon economists indicating that energy efficiency investments increase economic growth and job creation, and reduce income equality.

- Please provide a few specific examples of this cause and effect.

- How did each of these examples have a net economic benefit – with and without regard for grants, tax credits, or other outside incentives?

Questions from Senator Debbie Stabenow

Question 1: Your testimony highlights the unique infrastructure challenges our rural communities face and how now is the time to be investing more in rural communities.

One of the ways we secure critical investments in rural infrastructure is through a Farm Bill. These investments are targeted at improving the quality of life in rural communities - by investing in clean water infrastructure and energy efficiency measures for farmers and small businesses, and by modernizing our grid.

Would you please speak to how these critical investments bring jobs and economic growth to our rural communities?

Question 2: 87,000 people work in energy efficiency jobs in Michigan, representing the largest share of my state's clean energy workforce.

Despite the widely recognized benefits of energy efficiency to consumers and workers, the Trump Administration last year proposed a $1.4 billion cut to the Energy Department's Office of Energy Efficiency and Renewable Energy. Moreover, according to recent press reports, this year's budget request is expected to cut the energy efficiency office by 72 percent.

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In addition, the Administration reportedly intends to abolish the weatherization program, which has helped trained thousands of workers and reduce utility bills for homeowners.

Given all of the benefits of energy efficiency – from more jobs, to lower electric bills and emissions – do you believe the federal government should continue investing in programs that increase energy efficiency?

Questions from Senator Joe Manchin, III

Question 1: The decline of the coal industry has been devastating to my home state. We lost businesses and population. So we are looking for ways to revitalize our home state economy. I have been working for some time with Senator Capito to bring stakeholders together to help realize the potential of an Appalachian Storage Hub – an innovative energy infrastructure project that will attract manufacturing investment and create jobs. Our area is primed for this sort of energy project because of our abundant natural gas, natural gas liquids and natural geologic storage. This is exactly the type of effort is what Congress envisioned when it created the Title Seventeen loan program. The Loan Program Office (LPO) helps provide low cost capital to innovative energy projects in order to help alleviate investor concerns and get the project into development. The future of this program is currently in question though. So I'm concerned that Congress is going to unwittingly tie the hands of many energy infrastructure projects – not just this one – if we don't ensure this program is funded going forward.

As you reviewed the evolution of energy infrastructure in this country, do you believe the US government has had a role in innovating us to the next stage?

Is it fair to say that the loan program has had a profound impact on the evolution of how electricity is produced and delivered in this country today?

Question 2: On January 28, the Washington Post reported that a tanker carrying liquefied natural gas (LNG) from Russia arrived in Boston Harbor. That tanker had gas on it from the Yamal facility – a project largely financed by the Russian company Novatek. In July of 2014, after Russia annexed Crimea, the US Treasury Department issued sanctions that were specifically targeted at weakening the Russian energy sector – those sanctions forbid any financing for projects belonging to Novatek. Recognizing Boston was not its first step along the journey, it seems though that these sanctions do not prohibit the purchase of gas from this Russian project in the Arctic. So – in short – there is Russian LNG being turned back into gas at one of our ports and then being used to power American homes. Earlier this week, the Energy Information Administration released its Annual Energy Outlook for 2018. In the Reference case, natural gas production accounts for the largest share of total energy production - 39% by 2050. That's domestic fuel.

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My question is simple: Why, when we have one of the world's greatest reserves of natural gas sitting right under West Virginia, are we importing it at the risk of bolstering Russia's energy sector?

Questions from Senator Catherine Cortez Masto

Question 1: What alternatives can the federal government consider to encourage growth and local project development rather than walking back regulations more broadly?

Question 2: Your testimony refers to the electric grid as failing, but Mr. Mueller refers to it as "highly reliable and resilient, showing improved reliable performance year after year." What makes your two assessments differ?

Question 3: In reference to your testimony, what kind of community would be ideal to participate in a rural demonstration project? What factors would contribute to a rate of success?

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Questions from Chairman Lisa Murkowski

Question 1: You mention in your testimony that one of the reasons for great success in US shale production is the relatively seamless process to allow for natural gas delivery infrastructure development– through FERC – and there is a comparatively straightforward regulatory approval process for pipelines.

- **In foreign countries with significant shale resources, how do those nations grant permits to build out their pipeline infrastructure?**

To be clear, the process varies across countries and has resulted in very different infrastructure legacies around the world. In generality, infrastructure projects outside the US are typically done in cooperation with the foreign government, the local national energy company, and a multi-government institution (such as the European Union) when such over-arching interests exist. This process typically includes the conduct of a feasibility study and assessment of local environmental and economic impact, usually with the national energy company and other project developer input. If the pipeline infrastructure is directly tied to an upstream project, then the domestic portion of the facility is generally treated as part of the entire venture, in a vertically integrated manner. On the upstream portion of the investment, mineral resources are generally considered national property so any wealth generated from the extraction and sale of extracted resources contributes directly to government coffers, after cost recovery. Hence, the development of in-country pipeline infrastructure is often considered jointly with the upstream development activity as it is a vehicle for monetization and/or distribution of national wealth. However, if the pipeline infrastructure is destined to cross borders/jurisdictions, then the respective governments in each region are involved in the process.

We can see in very recent history how other governments are involved in pipeline infrastructure development. It is often the case that governments will react to a specific event by funding/ordering a feasibility study and the eventual streamlining of certain infrastructure developments, but there is very little in the way of competitive enterprise in these developments. This is also why costs are generally higher in other part of the world. We see this currently in Australia with the natural gas supply shortages in South Australia while other regions of the country are ramping up LNG exports. We also have seen this in Europe where concerns over Russian hegemony have prompted responses allowing greater flexibility in supply sourcing and delivery – ranging from LNG import infrastructure to pipeline flow reversal. And, we see this in Brazil where a large amount of associated natural gas in unable to move onshore for domestic use (and is re-injected) due to a lack of adequate pipeline capacity. To be clear, these are *infrastructure* issues.

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The development of such infrastructure in the US is facilitated by the existence of pricing signals that are clear and transparent and the ability for market participants to compete for the ability to trade across regions. According to FERC, the US has seen approval of over 20,000 miles of natural gas pipeline with nameplate capacity totaling 195 billion cubic feet per day since 2000 (see https://www.ferc.gov/industries/gas.asp). This scale of infrastructure approval is indicative of the scale of filed applications, all of which are motivated by market signals that prompt developers. Moreover, this is evidence of the manner in which markets in the US allow relatively rapid response to emerging local market imbalances if unimpeded. To be clear, this does not mean unexpected events, such as demand spikes or pipeline outages, will not occur and have significant implications for local prices. Indeed, these sorts of things will occur. However, the flexibility that has been observed in the US renders market access for both consumers and producers relatively seamless.

- **We have heard arguments that the FERC permitting process for pipelines should return, at least to some extent, to the era where there was a regulatory finding of need. Do you think that requiring such a finding or other administrative proxy is wise? In any event, how can these calls for more administrative process be reconciled with your testimony that the FERC process is a source of success?**

Historically, the "finding of need" was part of the rate-making process for regulated monopoly entities. Natural gas pipelines would buy gas from a *production* area and sale it in a *market* area in the absence of competition for the commodity transportation services. This rendered the pipeline to have monopoly power over the transport of the commodity. Hence, a regulatory authority would act to minimize the incentive to extract monopoly rents, but it had to also ensure the pipeline company adequately invested in capacity, which could be accomplished by providing a guaranteed rate of return to the pipeline asset. This, then, effectively de-risked the pipeline. Accordingly, if pipelines were to be guaranteed a rate of return, it was necessary to determine that pipeline developers only proposed projects that were actually needed to prevent them from over-building and inefficiently adding to their rate base. This type of regulated rate-making still exists today in regulated monopoly utility areas across electricity and natural gas markets, or where competition has not been introduced.

With the introduction of competition and the associated unbundling of capacity rights from facility ownership, the risk associated with pipeline construction was effectively transferred to developers. As a result, developers will now generally only move forward with pipeline development if sufficient open interest is nominated for new pipeline capacity. As a result, the "finding of need" is now effectively proxied by market participants demonstrating demands for new capacity, which is signaled by existing or anticipated price dislocations between regions. Hence, the existence of well-functioning and liquid markets provides adequate evidence of need. Anything that inhibits the translation of price signals to investment will effectively inhibit

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investment on both sides of any trade that a pipeline facilitates – from upstream activity to power plant development. These secondary impacts are important, especially when one considers their ramifications for supply-demand balance in various regional markets as well as environmental goals. So, a clear understanding of this should be part of any calculus aimed at moving the FERC process backwards.

The US pipeline market is a model for the international natural gas market. Stakeholders in other parts of the world (for example, from China, the Baltics and various countries especially in central and eastern Europe, and Australia) consistently seek out information – from us here at the Baker Institute and others (such as consulting firms) – regarding the operation and development of pipeline infrastructure in the US. Regarding the meetings held with Baker Institute fellows and scholars, in every case there is a clear desire expressed in these meetings for an ability to proxy what occurs here, alongside a recognition that the domestic regulatory overlay in those countries will not allow it.

Question 2: Your testimony defines the relationship between our nation's energy security and well-functioning energy markets and infrastructure.

- **Can you discuss how physical infrastructure enhances markets across regions and impacts delivered prices between regions when there are short-term movements in supply and demand?**

Physical infrastructure is necessary to facilitate trade between regions. When prices move in response to short-term demand or supply changes, an ability to connect to a neighboring region allows markets to rebalance much more quickly. We see evidence of this in the North American natural gas market. In previous analysis of the local price impacts of new pipeline infrastructure, it has been shown that both price level and price volatility are lower in the destination market when new delivery capacity is added (see, for example, http://www.cleanskies.org/wp-content/uploads/2011/08/LNGMarketGlobalizationImpact.pdf). The existence of adequate pipeline capacity alleviates the short-term constraints that arise when demand surges in response to stimuli such as weather. Given demand for energy in general is not constant – through a year, season or day – it is important that the delivery of energy services be very flexible. While such flexibility is certainly provided by pipeline capacity, it is also provided by other infrastructures – such as storage – as well as technologies and services that make demand more flexible.

- **It would seem that the lack of infrastructure contributes to something less than the most productive use of any fuel, suggesting that infrastructure can sometimes be a valuable tool in combating climate change and other environmental concerns. Do**

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you agree? Either way, please describe how infrastructure allows oil and gas to be sent to where it can provide society with the greatest value.

Infrastructure allows trade to occur between parties and for those who place the highest value on a particular commodity to receive it. In the case of climate change, infrastructure allows natural gas, for example, to displace more carbon intensive fuels in the generation of electricity and heat for industrial, commercial and residential use. If adequate infrastructure is not present, then those demands will be met through alternative means, which can include rail or freight (in the case of coal) and tanker or truck (in the case of heating oil). Note that this also holds for renewable energy sources in the electric power sector. In the absence of adequate transmission infrastructure, renewable resources simply cannot deliver generated electricity to market. This is raised in my written testimony with regard to the $7 billion infrastructure investment that was needed to allow Texas wind generation to reach consumers in the eastern half of the state.

Question 3: In Alaska, energy infrastructure has transformed our state --- from production on the North Slope to the small hydropower and microgrids that are moving our small and remote communities away from diesel.

- **Alaska is rich in mineral and energy resources, yet tapping those resources is often delayed by challenges in permitting. One example is the Donlin Creek Mine –a project that is almost 20 years in development, and which involves permitting a 320-mile natural gas pipeline in order to deliver affordable energy needed to operate the mine – infrastructure that could benefit the region as a whole.**
- **Can you address how insufficient energy infrastructure – domestically and globally – stands as a barrier to economic growth?**

If infrastructure to deliver energy to market is not available, an alternative form of energy will be sought, albeit usually at higher cost. If the cost of the alternative is high enough, then no energy will be delivered and the intended use will be foregone. This effectively kills the productive enterprise that was the intended point of use for the delivered energy. In turn, this inhibits economic growth by not allowing the multiplier effects of the original productive enterprise to matriculate to the broader economy. The above referenced example of the Donlin Creek Mine is a case in point. Namely, absent the needed infrastructure, the activity is less productive and hence cannot progress at the intended pace. Of course, the environmental costs must be reconciled, but as is evidenced by data available from PHMSA at DOT or NTSB, while not void of incidents, pipeline deliveries remain a very safe means of providing energy.

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Question from Senator Debbie Stabenow

Question: Currently, U.S. natural gas prices are largely determined by domestic supply and demand. This has helped keep prices low and attract new investments in the United States. In fact, cheap gas has helped bring $160 billion in new manufacturing investments to the U.S. since 2012. In Michigan, this means new jobs.

However, if we export a lot of LNG and it becomes linked to the global LNG market, our prices will be impacted by global demand – rather than domestic demand – which presumably could drive up the cost that our consumers and businesses pay for gas.

In your testimony, you associate increased U.S. LNG exports with energy security. Yet just last month, a tanker carrying Russian LNG docked in Boston to deliver gas because of supply crunches in the Northeast following prolonged cold winter weather.

So, we have Russian LNG being shipped to U.S. markets and Chinese state-owned companies investing large amounts of capital in U.S. gas projects; and just this week, the Energy Information Administration projecting that 69 percent of all U.S. gas will be consumed by 2050 – partly because we are sending more gas overseas. Considering all of this, could you help me understand how ramping up U.S. LNG exports is good for our economy, our manufacturers, our consumers, and our nation's energy security? I just don't see how that is possible.

Low cost fuels are critical stimulus for new capital investments and employment opportunities. Indeed, capital investments in energy-using manufacturing are part of the full infrastructure value chain that is required to realize the economic potential of US resource wealth. This is something I alluded to in my response to a question during testimony – that it is important to recognize infrastructure connects all aspects of the energy value chain both within and across energy sources, from producer to consumer, and should be considered as fully interconnected.

The statement, "if we export a lot of LNG and it becomes linked to the global LNG market, our prices will be impacted by global demand – rather than domestic demand – which presumably could drive up the cost that our consumers and businesses pay for gas" has a major presumption in it. Namely, the impact on domestic price will depend on the relative elasticity of domestic supply. When we introduce trade into a market, the implications for price are dictated by the elasticities, or price responsiveness, of foreign demand and domestic supply. If supply is relatively elastic, as research suggests is the case in North America, then the majority of the price impact from exports will occur abroad. I have written extensively on this subject (see, for example, https://www.bakerinstitute.org/research/us-lng-exports-truth-and-consequence/), including analysis performed for the US Department of Energy for its national interest determination regarding LNG exports (see https://www.bakerinstitute.org/research/macroeconomic-impact-increasing-us-lng-exports/).

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Central to this is an important premise of trade. Namely, increased US LNG exports will only occur if price is supportive of the trade. In other words, large scale LNG exports will not occur if price abroad is not high enough to support a profitable shipment of natural gas from US ports. Thus, if there is a cold winter in the US and domestic prices rise, capacity through LNG export terminals will be released back into the US market as exports will not be profitable on certain volumes (because, importantly, *capacity* to export does not guarantee *flow* of export). This acts as an effective injection of supply back into the US market that dampens upward price pressure by meeting demand. Importantly, this only occurs if LNG export infrastructure is in place because it allows for greater market fungibility. Consider, for example, the case where LNG export infrastructure is not developed. This would also result in less gathering and pipeline infrastructure and lower levels of upstream investment, thus affecting the entire value chain (hence everything is connected). In turn, this results in less supply that is available to be delivered to consumers in the event of a winter demand spike. Hence, in the absence of LNG export infrastructure, investments all the way through the value chain are dis-incentivized thereby resulting in less flexible domestic supply. So, yes, expanding the set of potential trades (fungibility) facilitates investment throughout the value chain thereby rendering domestic supply more responsive to short term price movements.

An important exception to the above thesis arises when there are factors that limit the set of opportunities for trade. You referenced the case of Russian LNG volumes reaching the US coast. The volumes, which were re-shipped from the UK, did originate in Russia, but they only arrived in the US because there was a profitable trading opportunity. In fact, the only reason Russian-sourced gas arrived in the US is because it was the lowest cost short-term option, which begets a different line of questioning. If Russian volumes to the US are deemed an issue, security or otherwise, then if a solution is to be affected, the appropriate questions are, "why was there a profitable trade opportunity to deliver those volumes to the US and why were Russian volumes the preferred source of supply?" The answer to this question is rooted in the seasonal price movements that grip the northeastern US almost every winter. When demand spikes due to weather, there is generally insufficient pipeline capacity to move volumes from the Middle Atlantic to New England. This results in sometimes extreme price movements that subsequently incentivize LNG imports and short term storage withdrawals from the limited storage capacity in the region, as well as some demand response from large users in the New England market area. These factors all simultaneously act to rebalance demand and supply, albeit at a higher price. Fortunately, these price pressures are short-lived because the weather-driven demand impetus is also short-lived. Nevertheless, the profitable import opportunity is created because LNG imports provide the next viable source of supply to meet demand when domestic supply cannot reach the New England market.

To be sure, LNG imports are not the only arbitrage mechanism that is theoretically available, although it is the only one in practice. For example, another potential option if pipeline capacity remains difficult to build (for commercial or policy reasons) would be to source LNG from the Gulf Coast. However, that option is not currently viable due to Jones Act provisions. So, given

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markets must balance, as price rises with demand, supply will ultimately be sourced from somewhere, in this case LNG from abroad. The alternative is for demand to be reduced until markets rebalance. This so-called "demand destruction" is not generally associated with positive economic outcomes.

Another point worth adding regards the potential role of storage in the Middle Atlantic region for meeting seasonal demand movements in the New England market. If adequate market access via pipeline were available from the Middle Atlantic to New England, the ability to arbitrage price movements in New England would provide Middle Atlantic storage developers additional incentive to expand natural gas storage capacity to capture seasonal arbitrage opportunities. This is especially true since there is very little storage capability in New England aside from LNG peak shaving facilities. Again, prices transmit signals for arbitrage that infrastructure investments – in pipelines and storage – allow to be captured.

You also raise the EIA's projection of natural gas depletion by 2050. If depletion begins to occur more rapidly, then domestic supply costs will rise. This will, in turn, abate exports because their profitability will be challenged. In sum, the dynamic market response is much more complicated as market participants will respond to price movements in a variety of ways that ultimately keep markets in balance and re-establish price equilibria.

While not explicit in your question, this highlights another issue related to sanctions. If sanctions are not adopted by a broad enough set of parties, then access to global markets for the sanctioned entity can render the policy much less effective. The sanctioned entity can deliver volumes to the global market. While these volumes may not actually reach the US, the volumes do create displacement opportunities for other volumes on the water to reach the US. In other words, while Russian natural gas itself may not arrive in New England, it does help other volumes to reach New England by displacement.

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Questions from Senator Joe Manchin III

Question 1: The decline of the coal industry has been devastating to my home state. We lost businesses and population. So, we are looking for ways to revitalize our home state economy. I have been working for some time with Senator Capito to bring stakeholders together to help realize the potential of an Appalachian Storage Hub – an innovative energy infrastructure project that will attract manufacturing investment and create jobs. Our area is primed for this sort of energy project because of our abundant natural gas, natural gas liquids and natural geologic storage. This is exactly the type of effort is what Congress envisioned when it created the Title Seventeen loan program. The Loan Program Office (LPO) helps provide low cost capital to innovative energy projects in order to help alleviate investor concerns and get the project into development. The future of this program is currently in question though. So, I'm concerned that Congress is going to unwittingly tie the hands of many energy infrastructure projects – not just this one – if we don't ensure this program is funded going forward.

As you reviewed the evolution of energy infrastructure in this country, do you believe the US government has had a role in innovating us to the next stage?

Yes, the US government has impacted infrastructure in a variety of ways. Going back to the earliest stages of infrastructure development, the regulatory architecture across the oil and gas landscape facilitated the development of a fairly robust backbone infrastructure. However, the redesign of regulation and oversight beginning in the late 1970s triggered a virtual revolution, allowing for better price signaling and more trade and hence greater infrastructure investment.

With regard to the LPO, historically energy infrastructure was controlled as part of a vertically integrated monopoly system. This owed largely to the fact that there are high costs of entry, meaning not just anyone can carry a balance sheet sufficient to underwrite infrastructure investment to enter the energy market. Thus, regulated rates of return were often the norm as regulators approved projects. Remnants of this legacy still exist today, but competitive bidding for large scale infrastructures is much more the norm. This, in turn, highlights the risks associated with financing infrastructure, particularly when banks and private equity is involved. Loan guarantees reduce the capital and financing burden of infrastructure investment and hence, market entry, thereby having the potential to enhance the competitive landscape. Of course, not all projects bear commercial success, but this does not render such programs "out-of-the-money." Rather, the portfolio of government-backed guarantees should be evaluated to determine if there is a positive return on investment. Single cases of failure, while headline grabbing, are not the relevant measures of success for such programs.

I have not rigorously evaluated the programs in this way, but my understanding is that they have seen both successes and failures. If greater risk aversion is desired, then, at the very least, a

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reassessment of how guarantees are awarded may be in order. But, such programs have a high enough potential that, in my assessment, they warrant remaining in place in at least some form.

Is it fair to say that the loan program has had a profound impact on the evolution of how electricity is produced and delivered in this country today?

This is an interesting question that requires a much deeper, case-by-case examination of the evolution of the electricity system. I am aware of work done by energy historians in this vein. For example, a recent book by Dr. Julie Cohn ("The Grid" available at https://mitpress.mit.edu/books/grid) explores the origins of the US electrical grid and how it evolved into the massive interconnected system that exists today. There is a mixed history of Federal and local government interaction with this process, including direct investment and financing support, which began as a series of many relatively small grids aimed at the provision of local electricity services and evolved through interconnection to provide more reliable service to all consumers. In effect, growth in fungibility through infrastructure and enhanced trading opportunities across regions increased reliability in the delivery of energy services.

<u>Question 2</u>: On January 28, the Washington Post reported that a tanker carrying liquefied natural gas (LNG) from Russia arrived in Boston Harbor. That tanker had gas on it from the Yamal facility – a project largely financed by the Russian company Novatek. In July of 2014, after Russia annexed Crimea, the US Treasury Department issued sanctions that were specifically targeted at weakening the Russian energy sector – those sanctions forbid any financing for projects belonging to Novatek. Recognizing Boston was not its first step along the journey, it seems though that these sanctions do not prohibit the purchase of gas from this Russian project in the Arctic. So – in short – there is Russian LNG being turned back into gas at one of our ports and then being used to power American homes. Earlier this week, the Energy Information Administration released its Annual Energy Outlook for 2018. In the Reference case, natural gas production accounts for the largest share of total energy production - 39% by 2050. That's domestic fuel.

My question is simple: Why, when we have one of the world's greatest reserves of natural gas sitting right under West Virginia, are we importing it at the risk of bolstering Russia's energy sector?

Please see my answer to the question posed by Senator Stabenow. It is the result of a lack of adequate pipeline infrastructure and policy overlays in the New England market area that limit access to US Lower 48 production. A point worth re-emphasizing is that if adequate market access were available from the Middle Atlantic region to New England, the ability to arbitrage price movements in New England would provide Middle Atlantic storage developers additional incentive to expand natural gas storage capacity.

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Questions from Chairman Lisa Murkowski

Question 1: In your testimony, you describe some of the earlier approaches by FERC to the question of when to approve a gas pipeline for construction. Specifically, you describe how in the 1980s, FERC would commonly consolidate different industry proposals to build pipelines that would serve the same markets. And that this approach failed.

- What are the key lessons-learned in that earlier era?

Answer: The principal lesson from this era is that consolidating competing pipeline applications for a single hearing created a litigious, protracted process that could significantly delay new pipeline capacity to meet a demonstrated market need. My written statement offered the example of the Boundary Gas proceeding during the 1980s in which it took seven years for FERC to issue a certificate of public convenience and necessity due to the need to consider competing applications. Some critics of FERC's current certificate policy statement have suggested a regional planning model for determining the need for natural gas pipeline capacity and selecting the project or projects to meet that need. It is hard to see how this would not result in the same litigious, protracted proceedings that characterized FERC's former model for reviewing pipeline applications.

- Today our nation is seeing great interest in building pipelines because of the shale revolution. Should FERC return to an approach I understand it took in the 1980s, and consolidate a number of those proceedings so that FERC itself could manage the development process?

Answer: No, FERC should not return to its prior approach, which was a product of the era in which interstate natural gas pipelines aggregated gas supply for resale as a bundled product. As part of restructuring the natural gas industry to a non-discriminatory, open-access transportation model, FERC concluded that a more market responsive policy for authorizing pipeline construction would advance Congress' goals in decontrolling natural gas prices at the wellhead, i.e., achieving consumer benefits from competition in natural gas commodity markets. There is no basis for returning to an approach founded upon an industry model that no longer exists.

- Do you think FERC Commissioners have a better ability to judge the wisdom of a pipeline investment compared with the persons who will actually be risking their own funds to make that investment?

Answer: FERC's certificate policy considers precedent agreements (that is, customer commitments to contract on a multi-year basis for firm pipeline capacity) to be strong evidence of need for a proposed pipeline. The demonstration of need is required for FERC to find that a proposed pipeline meets the statutory public convenience and necessity standard.

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While FERC's policy invites applicants to submit other proof of need, including the possibility to demonstrate need when there are not precedent agreements, these customer commitments are the most tangible, objective demonstration of need for new pipeline capacity. FERC's current policy is to look first to the judgment of those who will be putting capital at risk as a validation of need as the commission weighs whether a proposed pipeline meets the public convenience and necessity standard.

Question 2: In your testimony, you describe how FERC ensures that a pipeline will not be built "unless there is a demonstrated need." As you know, I care very much about the problem of climate change, but I am also concerned that energy remain affordable and available for and to every American.

- Do you think that FERC has adequate statutory authority when it balances the environment against the needs of people to get the gas that warms their home in the winter and keeps their lights on?

Answer: Yes, FERC has adequate statutory authority to balance the environmental impacts of a proposed pipeline versus the benefits to consumers that would receive the natural gas to be transported by the pipeline. Congress provided FERC with considerable discretion in applying the "public convenience and necessity" standard under section 7 of the Natural Gas Act. This discretion has been recognized by the courts, which has allowed FERC freedom in establishing pipeline certification criteria that consider both public need and environmental impact.

- And to be sure I understand, you aren't asking for pipelines to get a "pass" on vigorous review of environmental matters?

Answer: That is correct. A proposed pipeline is subject to a rigorous environmental analysis to satisfy the requirements of the National Environmental Policy Act. In addition, a pipeline must receive all necessary approvals under the applicable environmental laws (e.g., Clean Air Act, Clean Water Act, Endangered Species Act) prior to commencing construction. The receipt of such other approvals is a condition of the certificate issued by FERC under the Natural Gas Act.

- Where can we provide faster permitting without compromising environmental standards?

Answer: Faster permitting can be achieved in several ways. The first is by taking steps to promote the concurrent, rather than sequential, review of applications for the permits required to construct and operate a natural gas pipeline. The second is by promoting coordination and consistency within executive branch departments that are responsible for issuing multiple permits connected with a proposed pipeline. The principal example here is the Department of the Interior, where long linear infrastructure such as a pipeline may require permits from different agencies and bureaus within the department or where several regional offices of the same agency or bureau may need to issue permits. Third, to the extent practical, the lead agency, in this case FERC, should prepare a single NEPA document (an environmental assessment or an

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environmental impact statement) for a pipeline project that requires permits from multiple agencies.

The Energy Policy Act of 2005 incorporated many of these ideas for greater coordination in natural gas pipeline permitting. Unfortunately, EPAct 2005 did not include an effective means to enforce discipline upon this process.

- To what extent does a policy of stopping infrastructure actually have an adverse impact on the environment? Can you provide examples of infrastructure that actually improved the environment by allowing access to cleaner fuels?

Answer: Stopping infrastructure can have an adverse impact on the environment if it frustrates the ability to utilize cleaner forms of energy. Yes, an example of where new infrastructure has improved the environment is the Spectra Energy (now Enbridge) New York-New Jersey Expansion Project that entered service in 2013. This was the first new natural gas transmission pipeline built into Manhattan in over 40 years. The natural gas delivered by the pipeline enabled New York City to achieve its clean air goals by displacing high sulfur fuel oil.

- Can you comment on the point that natural gas is, in many instances, a fuel that can be much better for the environment than alternatives? Can blocking construction of a gas pipeline result in environmental damage?

Answer: Yes, such damage can result if blocking a pipeline results in the continued consumption of fuels that are less environmentally benign than natural gas delivered by pipeline. The delivery of natural gas to the New England states is limited by pipeline capacity constraints. As a result, electric generators in New England are fueled with oil and with re-gasified liquefied natural gas delivered by ocean tankers during the peak winter months when natural gas local distribution companies are fully utilizing their firm pipeline capacity to satisfy the heating needs of homes and businesses. Neither of these alternatives is as environmentally benign as natural gas delivered by pipeline. Submitted for the record is an editorial addressing this point that was published in the Boston Globe on February 13, 2018.

Question 3: Please tell us more about the concept of "Cooperative Federalism" as you described it.

- Are you suggesting that Congress must do more to ensure that one state cannot stop a neighboring state from pursuing certain benefits for its citizens, for example, delivery of domestically-produced natural gas? It seems to me that your concept, if I understand it, is as old as the constitution.

Answer: Yes, that is our point. We respect the rights of states to protect the resources within their borders and the cooperative federalism model upon which environmental laws such as the Clean Water Act are built. It is not cooperative federalism, however, when a state's abuse of its authority affects the ability of other states and their citizens to enjoy the benefits of interstate

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commerce. That is what has happened with the State of New York's abuse of its authority under section 401 of the Clean Water Act to veto effectively FERC's determination that an interstate natural gas pipeline is in the public convenience and necessity. Pennsylvania, other upstream producing states, and their citizens are denied the benefits of a downstream market for their natural gas and the New England states and their consumers are denied the lower energy costs made possible by additional natural gas supplies.

- And a related question, what should Congress do to ensure that the federal and state governments respect one another's roles and don't abuse authority they have or have been given by delegation under federal laws?

Answer: Congress can amend section 401of the Clean Water Act to clarify the limits of state authority in connection with water quality consistency certifications and to provide recourse via an administrative appeal to a federal agency should a state exceed the bounds of its authority or act in a way that is contrary to the national interest. This administrative appeal to a federal agency would be similar to what already exists in the Coastal Zone Management Act.

Question 4: Can you discuss the level of new capital investment that will be needed to address future demand for new pipelines?

Answer: In 2016, ICF International published a study, North American Midstream Infrastructure Through 2035: Leaning into the Headwinds, sponsored by the INGAA Foundation. The study looked at two distinct scenarios reflecting distinctly different paths for natural gas, crude oil and natural gas liquid supply growth and market development. Assuming the midpoint of these two scenarios, $310 billion in capital expenditures for midstream natural gas infrastructure will be needed between 2015-2035. This includes natural gas transmission pipelines, integrity management and emissions control, gathering systems, and gas storage and LNG export facilities. As part of this, $166 billion will be needed for natural gas transmission pipelines.

ICF will be updating this study for the INGAA Foundation in 2018. We will provide the committee with the updated study when it is published.

Question 5: As I am sure you are aware, our Committee has held a number of hearings on the issue of grid security over the past year, covering issues like cyber security, Electro-Magnetic Pulse (EMP), weather, and other threats. We've also heard from DOE, FERC, the National Labs, and others about the various groups attempting to address this problem.

- Are efforts today sufficient to address future threats? Specifically, is the government getting needed information to the utilities, and vice versa, are utilities getting their operational data to government agencies in the best position to act upon it? What else should be done?

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Answer: INGAA represents the operators of interstate natural gas transmission pipelines. We do not represent the operators of electric and gas utilities. Still, there is a close economic and operational connection between our member companies' operations and those of natural gas and electric utilities. Likewise, protection against the threats referenced in your question is important to our members.

It is imperative that pipeline operators have real-time access to cybersecurity threats and information so they are appropriately equipped with the resources to manage rapidly evolving cyber threats. Operators leverage a number of mechanisms to share information including information sharing and analysis centers (ISACs) as well as strong partnerships with TSA and DOE. However, the over classification of information coupled with limited access to security clearances continues to be a challenge that limits operators' ability to access and share information in a timely manner.

In addition, we strongly urge "the various groups attempting to address this problem" to leverage existing constructs through the sector coordinating councils. These groups need to work together and alongside industry partners on these efforts to ensure no duplication of effort and no needless redundancy in the dedication of federal resources, as well as minimize the burden placed on industry.

Questions from Senator Ron Wyden

Question 1: Hurricanes Maria and Irma reminded us of the vulnerability of our critical energy infrastructure to natural disasters. I want to make sure that steps are being taken to protect Oregonians from the impacts of a disaster such as an earthquake in the Cascadia subduction zone.

What are pipeline companies doing to take the lessons learned from the aftermath of Hurricanes Maria and Irma, and use them to increase the resilience of mainland infrastructure to a massive disaster that could affect an area larger than one city?

Answer: Although a full-scale study has yet to be completed, natural gas pipelines appear to have functioned with minimal disruption during the recent U.S. hurricanes Maria and Irma.

The physical operations of natural gas production, transmission and distribution make the system inherently reliable and resilient. Disruptions to natural gas service are rare. When a disruption happens, it does not necessarily result in an interruption of scheduled deliveries of natural gas supply because the natural gas system has many ways of offsetting the impact of the disruption.

The natural gas system is not particularly vulnerable to weather-related events. Natural gas pipelines are predominantly underground and protected from the elements. Therefore, natural

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gas systems are far more resilient in the face of extreme weather events than electric systems. For example, in 2016, fewer than 100,000 natural gas customers nationally experienced disruptions, while 8.1 million Americans experienced power outages.

Moreover, according to an April 2017 INGAA survey of 51 interstate pipelines, over the ten-year period 2006-2016, pipelines delivered 99.79 percent of "firm" contractual commitments to firm transportation customers at primary delivery points (i.e., the points specified in their contract). As attested to by INGAA's survey data, firm pipeline transportation service historically is extremely reliable.

The inherent characteristics of natural gas are an important factor that cannot be overlooked. Unlike electricity that travels at the speed of light and flows along a path of least resistance, natural gas moves by pressure. Gas moves through the transportation system using compressors that pressurize the gas to move it over distance. For long distances, compressors are placed at regular intervals to continue the forward movement. In sharp contrast to electricity, natural gas physically moves through a pipeline at an average speed of 15-20 miles per hour, and its flow can be controlled. This allows time for pipeline operators to react and respond.

Question: In your view, what should the Federal government be doing to increase the resiliency of our energy infrastructure to an event such as a major earthquake?

Answer: INGAA's answer to the following question addresses this question as well.

Question 2: In 2013, Oregon's Department of Geology and Mineral Industries (DOGAMI) issued a report that identified vulnerabilities to the state's Critical Energy Infrastructure hub, which is on a bank of sandy soil next to the Willamette River. DOGAMI noted that, during a major earthquake, that soil could liquefy and severely disrupt fuel and electricity supply lines.

What steps should pipeline companies be taking to assess seismic risks to their infrastructure, and implement seismic mitigation plans?

Answer: Section 29 of the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 directs operators of gas transmission pipelines to consider seismicity when identifying and evaluating potential threats in accordance with 49 CFR Part 192 (minimum federal safety standards for transportation of natural and other gas by pipelines). In 2016, the Pipeline and Hazardous Materials Safety Administration proposed a new regulation to codify the requirement for operators to identify and evaluate threats such as "weather related and outside force damage; including consideration of seismicity, geology, and soil stability of the area" as part of the integrity management plans required for pipelines that operate in high consequence areas. Furthermore, PHMSA proposed a new inspection and remediation regulation for all gas transmission pipelines "following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event…"

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INGAA supports the new regulations related to seismicity and extreme weather events. PHMSA's Gas Pipeline Advisory Committee (GPAC) endorsed both proposed regulations in 2017. PHMSA's GPAC is charged with reviewing PHMSA's proposed regulatory initiatives to assure the technical feasibility, reasonableness, cost-effectiveness and practicability of each proposal. The proposed regulations related to seismicity and extreme weather events are components of an extensive proposed rulemaking on a wide array of gas transmission pipeline safety topics, which the GPAC will continue to review in 2018 before PHMSA finalizes its proposed rule.

Questions from Senator Joe Manchin, III

<u>Question 1</u>: The decline of the coal industry has been devastating to my home state. We lost businesses and population. So we are looking for ways to revitalize our home state economy. I have been working for some time with Senator Capito to bring stakeholders together to help realize the potential of an Appalachian Storage Hub – an innovative energy infrastructure project that will attract manufacturing investment and create jobs. Our area is primed for this sort of energy project because of our abundant natural gas, natural gas liquids and natural geologic storage. This is exactly the type of effort is what Congress envisioned when it created the Title Seventeen loan program. The Loan Program Office (LPO) helps provide low cost capital to innovative energy projects in order to help alleviate investor concerns and get the project into development. The future of this program is currently in question though. So I'm concerned that Congress is going to unwittingly tie the hands of many energy infrastructure projects – not just this one – if we don't ensure this program is funded going forward.

As you reviewed the evolution of energy infrastructure in this country, do you believe the US government has had a role in innovating us to the next stage?

<u>Answer</u>: The US natural gas transmission pipeline industry has been developed entirely with private capital. (The one exception to this blanket statement would be the World War II "inch" pipelines that were converted to transport natural gas. These assets were sold to private, investor-owned companies over seven decades ago.) Consequently, INGAA's members have had no experience with the loan program referenced in your question.

What we can add is that, given the nature of the shale resources (i.e., natural gas liquids present in "wet" natural gas, associated gas produced in conjunction with crude oil), the development of pipeline infrastructure often is synergistic. That is, the production of natural gas, and the pipelines that make it possible to sell gas profitably to downstream markets, create the need for infrastructure to deliver the NGLs processed from the natural gas. It is reasonable to anticipate that the imperative to find a market for the NGLs processed out of the stream of produced natural gas would contribute to demand for an infrastructure project such as the Appalachian Storage Hub.

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<u>Question</u>: Is it fair to say that the loan program has had a profound impact on the evolution of how electricity is produced and delivered in this country today?

<u>Answer</u>: As noted, INGAA is unfamiliar with the loan program. Therefore, we cannot comment on its impact on the production and delivery of electricity.

<u>Question 2</u>: On January 28, the Washington Post reported that a tanker carrying liquefied natural gas (LNG) from Russia arrived in Boston Harbor. That tanker had gas on it from the Yamal facility – a project largely financed by the Russian company Novatek. In July of 2014, after Russia annexed Crimea, the US Treasury Department issued sanctions that were specifically targeted at weakening the Russian energy sector – those sanctions forbid any financing for projects belonging to Novatek. Recognizing Boston was not its first step along the journey, it seems though that these sanctions do not prohibit the purchase of gas from this Russian project in the Arctic. So – in short – there is Russian LNG being turned back into gas at one of our ports and then being used to power American homes. Earlier this week, the Energy Information Administration released its Annual Energy Outlook for 2018. In the Reference case, natural gas production accounts for the largest share of total energy production - 39% by 2050. That's domestic fuel.

My question is simple: Why, when we have one of the world's greatest reserves of natural gas sitting right under West Virginia, are we importing it at the risk of bolstering Russia's energy sector?

<u>Answer</u>: Importing Russian LNG to meet peak energy demand in New England illustrates how pipeline infrastructure capacity constraints can affect energy choices and, ultimately, consumer costs. New England during high-demand periods lacks adequate pipeline capacity. As a result, electric generators in New England are fueled with oil and with re-gasified LNG delivered by ocean tankers during the peak winter months when natural gas local distribution companies are fully utilizing their reserved pipeline capacity to satisfy their obligation to heat homes and businesses. This situation is especially vexing because the Marcellus Shale sits on the figurative "doorstep" of New England.

In answering a question at the February 8 hearing, I noted the disparity in the prices reported for the delivery of natural gas on January 6, 2018 (i.e., during the severe cold wave). The price for natural gas delivered to Boston was $78.80 per million Btus (MMBtu) while the price at Leidy, Pennsylvania (in the Marcellus Shale) was $4.20 per MMBtu. If there had been no pipeline constraints, the price differential should have been little more than the FERC-regulated rate for pipeline transportation between the two locations. An illustrative transportation cost between these locations is less than $0.40 per MMBtu.

Why haven't these bottlenecks been relieved by adding new or expanded pipeline capacity into New England? First, given the economics and regulation of the pipeline industry, new pipelines are not built on speculation. A pipeline company is unlikely to make the capital investment, and

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FERC is unlikely to find need, unless customers are willing to enter long-term, firm contracts for a proposed pipeline. Second, while the incremental demand for natural gas in New England is represented principally by electric power generators, the wholesale power market rules in ISO New England do not reward generators for holding firm pipeline capacity, i.e., there is no assurance that the cost will be recoverable in the prices at which generators sell electricity.

In addition, the effort by the State of New York to use section 401 of the Clean Water Act to block an interstate natural gas pipeline that FERC has found to be in the public convenience and necessity frustrates the ability to expand the delivery of natural gas to New England. While the route of the proposed Constitution Pipeline does not include any New England state, the pipeline would connect in New York with two other interstate pipelines that serve parts of New England. Consequently, New York's energy roadblock thwarts the interstate commerce that would connect natural gas producers and consumers in neighboring states.

Question 3: Following the Bomb Cyclone, this Committee held a hearing on grid performance. Andy Ott, the chief executive officer of PJM – the regional transmission operator which includes West Virginia – and I discussed how critical coal-fired power plants were to keeping the lights on and houses warm. In fact, Mr. Ott agreed that we couldn't have done it without coal. During that hearing we also discussed how well natural gas fired generation performed – unfortunately we also witnessed price spikes due to limited pipeline capacity. It seems to me that if we want to fully realize an "all of the above" energy future, we must utilize our abundant supplies of natural gas by ensuring that natural gas can get to areas of demand – like the northeast. That means responsible expansion of pipeline infrastructure.

How do we enhance coordination and collaboration amongst permitting agencies? Because it seems to me that – in many instances – to secure one permit you to have secure three others first. And if those agencies aren't talking to one another, a pipeline developer becomes a go between.

Answer: Yes, it would be valuable to achieve concurrent, rather than sequential, reviews of the applications for the various permits that must be obtained to construct an interstate natural gas pipeline. Congress attempted to address this situation by enacting the new Natural Gas Act section 15(a)-(d) on process coordination and section 19(d) on judicial review as part of the Energy Policy Act of 2005. This legislation was intended to strengthen FERC's role as the lead permitting agency for interstate natural gas pipelines. Unfortunately, these provisions have not been entirely successful in achieving their intended purpose.

Legislation now pending before Congress, the House-passed H.R. 2910, and the Senate-introduced S. 1844 and parts of S. 1460, proposes incremental improvements to advance the goals of the EPAct 2005 amendments. We encourage the enactment of this legislation.

These goals also are being advanced through executive branch reform initiatives. For example, implementation of Executive Order 13807, Establishing Discipline and Accountability in the

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Environmental Review and Permitting Process for Infrastructure, has the potential to achieve the harmonization in permitting that we believe is needed.

Question: In your opinion, will improved policies for firm contracts for natural gas help?

Answer: Policies to encourage pipeline shippers to enter firm contracts could help to relieve capacity constraints, such as those that prevent natural gas consumers in New England from taking full advantage of the natural gas abundance made possible by the Marcellus Shale.

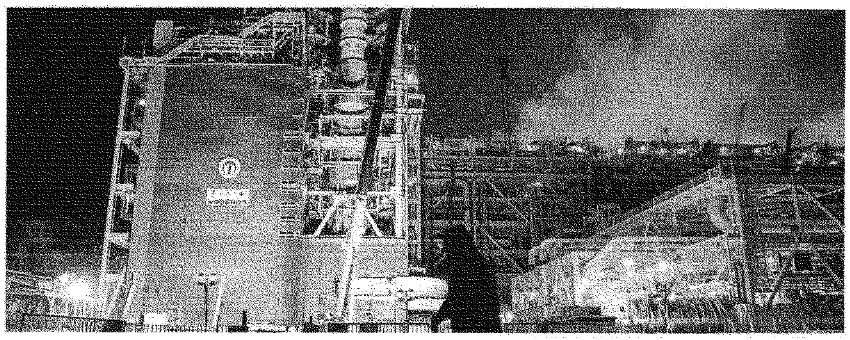
Question 4: I have heard reports of federal agencies taking more than a year to review an application to simply survey a small area of federal lands. In one instance, I believe that once that application was approved the actually survey took less than a day. Understanding there are often resource and funding constraints that play into this type of scenario, it seems to me that these timelines are disproportionately long. I believe that federal agencies must ensure that any activities associated with permitting infrastructure must be done in a safe and environmentally responsible manner and that includes a focus on conservation. But a year seems too long for a simple survey.

Can you provide your perspective on how streamlining the permitting process will cut back on delays while still maintaining the preservation of the land and water which these projects traverse?

Answer: Coordinating the permitting process for interstate natural gas pipelines does not mean preempting or limiting the ability of an agency to perform the role given to it by Congress. It also does not mean compromising safety or the environment when applications for such permits are considered.

Experience demonstrates that implementing the various permitting mandates in an uncoordinated manner can delay and frustrate the timely and predictable approval of pipeline projects. Efforts can, and should, be made to avoid this result.

The Boston Globe



Maxim Zmeyev/AFP/Getty Images/File

The Yamal LNG plant is about 1,550 miles from Moscow. In December, it exported its first liquefied natural gas shipment, which ended up in Boston.

Our Russian 'pipeline,' and its ugly toll

By The Editorial Board,

February 13, 2018

To build the new $27 billion gas export plant on the Arctic Ocean that now keeps the lights on in Massachusetts, Russian firms bored wells into fragile permafrost; blasted a new international airport into a pristine landscape of reindeer, polar bears, and walrus; dredged the spawning grounds of the endangered Siberian sturgeon in the Gulf of Ob to accommodate large ships; and commissioned a fleet of 1,000-foot icebreaking tankers likely to kill seals and disrupt whale habitat as they shuttle cargoes of super-cooled gas bound for Asia, Europe, and Everett.

On the plus side, though, they didn't offend Pittsfield or Winthrop, Danvers or Groton, with even an inch of pipeline.

This winter's unprecedented imports of Russian liquefied natural gas have already come under fire from Greater Boston's Ukrainian-American community, because the majority shareholder of the firm that extracted the fuel has been sanctioned by the US government for its links to the war in eastern Ukraine and Russia's illegal annexation of Crimea. Last week, in response to the outcry, a group of Massachusetts lawmakers, led by Senator Ed Markey, blasted the shipments and called on the federal government to stop them.

But apart from its geopolitical impact, Massachusetts' reliance on imported gas from one of the world's most threatened places is also a severe indictment of the state's inward-looking environmental and climate policies. Public officials, including Attorney General Maura Healey and leading state senators, have leaned heavily on righteous-sounding stands against local fossil fuel projects, with scant consideration of the global impacts of their actions and a tacit expectation that some other country will build the infrastructure that we're too good for.

As a result, to a greater extent than anywhere else in the United States, the Commonwealth now expects people in places like Russia, Trinidad and Tobago, and Yemen to shoulder the environmental burdens of providing natural gas that state policy makers have showily rejected here. The old environmentalist slogan — think globally and act locally — has been turned inside out in Massachusetts.

But more than just traditional NIMBYism is at work in the state's resistance to natural gas infrastructure. There's also the $1 million the parent company of the Everett terminal spent lobbying Beacon Hill from 2013 to 2017, amid a push to keep out the domestic competition that's ended LNG imports in most of the rest of the United States.

And there's a trendy, but scientifically unfounded, national fixation on pipelines that state policy makers have chosen to accommodate. Climate advocates, understandably frustrated by slow progress at the federal level, have put short-term tactical victories against fossil fuel infrastructure ahead of strategic progress on reducing greenhouse gas emissions, and so has Beacon Hill. They've obsessed over stopping domestic pipelines, no matter where those pipes go, what they carry, what fuels they displace, and how the ripple effects of those decisions may raise overall global greenhouse gas emissions.

The environmental movement needs a reset, and so does Massachusetts policy. The real-world result of pipeline absolutism in Massachusetts this winter has been to steer energy customers to dirtier fuels like coal and oil, increasing greenhouse gas emissions. And the state is now in the indefensible position of blocking infrastructure here, while its public policies create demand for overseas fossil fuel infrastructure like the Yamal LNG plant — a project likely to inflict far greater near and long-term harm to the planet.

Maxim Zmeyev/AFP/Getty Images

The settlement of Sabetta on the Yamal Peninsula in the Arctic circle.

"ALL IS GLOOM AND ETERNAL SILENCE," wrote a 19th century English traveler in an awestruck account of the Kara Sea, then still a largely uncharted domain of ice floes and fog. Though more powerful vessels and melting ice have enabled more human activity in the Arctic, the area around Yamal, an indigenous name meaning "edge of the world," remains a refuge. An estimated 2,700 to 3,500 polar bears live in the Kara Sea region, along with the ring seals that form a crucial part of their diet.

Opening a gas export facility in such a harsh environment required overcoming both political obstacles — the US sanctions delayed financing — and staggering triumphs of industrial engineering by a workforce that reportedly reached 15,000 people. Dredgers scooped away 1.4 billion cubic feet of seabed to make room for the ships and built a giant LNG facility on supports driven into the permafrost, all in temperatures that can plunge to less than minus 50 degrees Fahrenheit.

The oil and gas industry poses serious threats, especially in an area like the Arctic that recovers slowly from damage, and in 2016 the Russian branch of the World Wildlife Fund issued a report warning of Yamal LNG's potential dangers. White toothed whales, a near-threatened species, breed in the vicinity of the facility, and the noise from shipping and the presence of more giant vessels "may force toothed whales to leave this habitat, which is crucial for their living, feeding, and reproduction."

The giant "Yamalmax" icebreaking tankers, longer than three football fields and designed to mow through ice up to six feet deep, are also "extremely bad news for any ice-associated mammals that should be in the vicinity of their path," said Sue Wilson, who leads an international research group based at the University of Leeds in the United Kingdom. The group has recently published a paper in the journal Biological Conservation on the impact of icebreakers on seal mothers and pups in the Caspian Sea and is currently studying shipping impacts in the Arctic.

"The captain is unlikely to notice — or even be able to see — seals in the vessel's path ahead," she said. "Even if the captain does notice, the fact that the ship is designed to proceed at a steady pace means that it is unlikely to attempt to stop for seals or maneuver around them, even if the ship can be slowed or stopped in time."

Advocates also worry that increased Arctic production and shipping will hurt indigenous people; sever reindeer migration routes ; import invasive species to an environment ill-equipped to deal with them; and introduce the very remote, but potentially cataclysmic, danger of an LNG explosion.

Finally, the gas pumped there will contribute to global climate change. In some parts of the world, especially China, LNG may provide climate benefits by displacing dirtier coal. If LNG displaces gas carried by pipeline, however, the math works out differently: Liquefied natural gas generally creates more emissions, since the process of cooling it to minus 260 degrees Fahrenheit and then shipping and regasifying it requires more energy than pumping natural gas through all but the longest and leakiest pipelines.

"The bottom line is that because of the nature of the liquefaction process, LNG is fairly carbon intensive," said Gavin Law, the head of gas, LNG, and carbon consulting for the energy consulting firm Wood Mackenzie. The exact difference depends on factors like how much pipelines leak, carbon impurities in the gas, age of equipment, and distance shipped, but generally LNG produces 5 to 10 percent more emissions over its whole life cycle from start to finish, he said.

From a planetary perspective, it doesn't matter where those emissions occur: Whether from the plant in Yamal, or the power plant in Everett, they have the same impact. The science should make the state's decisions straightforward.

"Natural gas has shown itself to be an important bridge to a clean energy future," said Ernest J. Moniz, the former secretary of energy in the Obama administration. "For New England, expanding the pipeline capacity from the Marcellus" -- the area of shale gas production in Pennsylvania -- "makes the most sense."

"Life cycle emissions for LNG imports to Boston certainly are higher than they would be for more Marcellus gas," he said.

But the upstream emissions typically don't show up on the books of states like Massachusetts, which judge the success of their climate efforts based only on how much greenhouse gas they emit within their own borders.

That's an accounting fiction. But it's a convenient one for lawmakers who've bowed to pressure to legislate based on what's visible inside the Commonwealth's own borders.

FROM MASHPEE TO SPRINGFIELD, Taunton to Sudbury, the message was clear: To fight climate change, the state shouldn't allow more fossil fuel pipelines or other infrastructure in Massachusetts.

That's what state senators Marc Pacheco and Jamie Eldridge, the heads of the state Senate's Committee on Global Warming and Climate Change, heard when they conducted a listening tour of the state — whose results they released on the same day the Russian gas was unloading in Everett — to help prepare a new energy bill.

The resulting legislation was introduced this Monday. It contained many fine ideas, including boosting the state's renewable energy requirements. But it also would raise obstacles to pipelines that would lock in the state's reliance on foreign gas, with its higher carbon footprint.

In an interview, Pacheco said "Obviously any fossil fuel investments are problematic," no matter where they occur, but that "we have no control over what happens in Russia or anywhere else in the world." Eldridge said, "I think this bill takes a big step to preventing pipelines," and also expressed concern about the LNG the state imports instead. "I think activists need to think about where a large amount of this gas is coming from, and that could be something the Legislature could take a look at" in the future, he said.

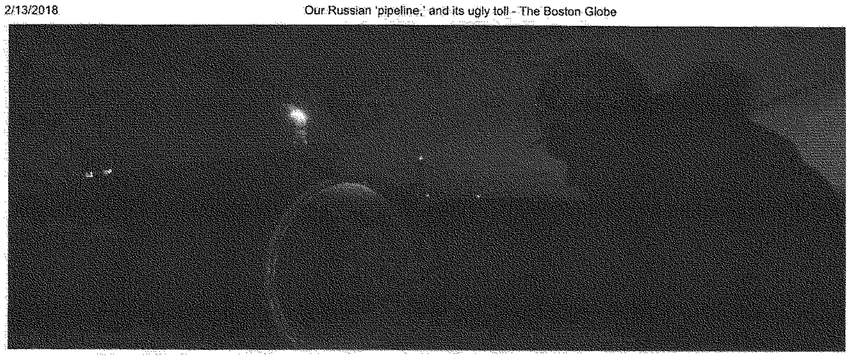
Theirs isn't the first analysis to miss the larger picture.

In 2015, the Conservation Law Foundation, a prominent environmental advocacy group in Boston, released a report dismissing the need for new pipeline capacity in New England, and called on the region to rely on a "winter-only LNG 'pipeline,' " including imported gas, to meet its winter energy needs instead.

After the first shipload of Russian gas arrived, David Ismay, a lawyer with the group, stood by the recommendation and shrugged off the purchase of Russian gas from the Arctic as simply the nature of buying on the worldwide market. "I think it's important to understand that LNG is a globally traded commodity," he said in an interview with the Globe.

The foundation, he said, hadn't compared the overall greenhouse gas emissions from LNG to pipeline gas from the Marcellus to determine which was worse for the climate, nor had it factored the impact on the Arctic of gas production into its policy recommendations.

But a state policy that doesn't ask any questions about its fuel until the day the tanker floats into the Harbor abdicates the state's responsibility to own up to all consequences of its energy use — and mitigate the ones that it can.



Maxim Zmeyev/AFP/Getty Images

A worker inspected a pipe in the port of Sabetta on the Kara Sea.

WHEN AN ICEBREAKER BEARS DOWN on a mother seal during the springtime breeding season, the terrified animal tries to scurry away with her pup. The two may leave a trail of urine and feces on the ice, telltale signs of their distress. Even if the animals survive the collision, the disruption may separate the mother and pup, leading to the pup's death.

Conscientious companies can minimize the cruel realities of global shipping — or conscientious governments can force them to. American law, for instance, requires ships to maintain a safe distance from seals and walruses in ice habitats. Wilson, the seal researcher, also suggested that icebreakers can change routes to avoid known seal habitats, especially during the breeding season, and carry trained observers onboard to advise vessel captains and record any adverse impact, particularly on mothers and young.

The Globe attempted to contact Sovcomflot, the Russian state-owned shipper in St. Petersburg that handled the first leg of the first shipment from Siberia to Everett, about what policies, if any, it employs to avoid killing seals and other wildlife, and whether it would halt LNG shipments during the spring as mother seals nurse their pups in the Arctic.

As of Monday night, it had not responded to e-mails.

The policy of Massachusetts, apparently, is to hope that the Russians are on top of it — and that the world beyond the state's borders manages the impacts of fossil fuel production and transportation that the Commonwealth buys and uses, but considers itself too pure to handle itself.

As of Monday night, the next shipment of Russian gas was anchored about 70 miles off Gloucester.

AMERICAN PUBLIC GAS ASSOCIATION

Submitted Testimony of the American Public Gas Association to the Senate Committee on Energy and Natural Resources on Energy Infrastructure

A Consumer Perspective

On behalf of the American Public Gas Association (APGA), we appreciate this opportunity to submit testimony to this important hearing addressing the future of this country's infrastructure.

APGA, the national association for publicly owned natural gas distribution systems, is in a unique position to offer testimony on this matter because of its members' proximity to the consuming public. APGA represents over 740 public gas systems in almost 40 states. Publicly-owned gas systems are not-for-profit, retail distribution entities owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that own and operate natural gas distribution facilities in their communities. Public gas systems' primary focus is providing safe, reliable, and affordable natural gas service to their customers.

At the most basic level, APGA represents the views of American natural gas consumers. Our members serve homeowners and small businesses which rely on affordable natural gas to heat their homes and water, cook their meals, dry their clothes, power their restaurants, schools and hospitals, and service businesses of all types.

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As the debate on our energy future continues, it is clear that natural gas should be a foundation for our energy future. As this Committee begins to address our energy infrastructure needs, we would like to see this Committee support dynamic federal programs that allow communities to choose how to best meet their energy needs without establishing any bias or embedded preferences.

As our nation discusses our future energy infrastructure needs, the Committee must not overlook the fact that the direct use of natural gas plays a critical role in the reliability, resiliency, efficiency, and security of the overall U.S. energy system. The direct use of natural gas today provides relief for our congested and stressed electrical infrastructure, as well as primary energy for on-site back-up generators during grid outages. Often lost in the dialog about the nation's energy resiliency is that diversity of delivery mechanisms (pipelines and electric transmission) and fuel sources and fuel reliance is key to ensuring overall system reliability. A fresh example is the current winter season, in particular the extreme weather of January 2018. According the American Gas Association, local gas utility preparation and the diversity of gas supply met an extreme challenge. On January 1, 2018, forty-two percent of natural gas delivered to consumers was sourced from underground storage infrastructure. Domestic production of natural gas sustained 72 billion cubic feet (Bcf) per day, which was supplemented with Canadian imports as high as 8 Bcf per day. The natural gas energy delivered to consumers on January 1st was equal to about 1700 giga-watts (GW) equivalent electricity. To put this in perspective, total generation capacity in the U.S. today is only about 1000 GW. Natural gas is indeed foundational to our nation's energy resiliency.

Natural gas is currently distributed to approximately 75 million homes and businesses nationwide. The use of natural gas appliances in homes and businesses frees up critical capacity and increases flexibility for the electric grid while lowering costs, improving overall efficiency, and reducing emissions. Similar to electricity conservation, natural gas appliances reduce the strain on the electricity grid while minimizing the need for the construction of additional generation plants and transmission lines. According to APGA's Levelized Cost of Energy Study[1], the direct use of natural gas has significantly lower levelized costs to consumers when compared to any of the electric generation technologies.

Expanding natural gas direct-use will benefit the nation in several ways. Natural gas will reduce the impact on consumers from the tremendous costs associated with the build out of additional electric generation and transmission assets. Consumers will also benefit from lower monthly utility bills when operating natural gas appliances as compared to electric alternatives.

The Committee should explore increasing utilities' ability to help expand their distribution capabilities. The expansion of a community's natural gas service is a key component to local and regional economic revitalization. Natural gas provides stable and low-cost energy to manufacturing and industrial businesses -- an invaluable benefit that can attract investment and provide increased economic activity across the country. Our members have continued to look for ways to better serve their community by upgrading and expanding service to new areas.

[1] APGA published the "Levelized Cost of Energy: Expanding the Menu to Include Direct Use of Natural Gas" study in August 2017 to look at the levelized cost of electricity generation options and the direct use of natural gas.

In many instances this is driven by the agricultural sector and the desire to provide farms and other agribusinesses with low cost energy. One of the biggest challenges to serving rural communities is lowering the initial infrastructure cost for end users – also known as "last mile" programs. Natural gas utilities must recoup all of the costs associated with expanding into new areas and this can be difficult in rural areas where lower population density increases the cost per customer. The Committee should explore how the government can help lower these cost for farmers and other agribusinesses that are often high energy users. A 2017 National Association of Regulatory Utility Commissioners Task Group on Natural Gas Access and Expansion Report provides an overview of the impact "last mile programs" have on dramatically lowering businesses' and underserved communities' energy bills.

Natural gas infrastructure can also help improve the overall resiliency of our national energy system. Given that natural gas pipelines are predominantly underground and therefore protected from the elements, natural gas infrastructure is not as susceptible to weather-related events. The Natural Gas Council released a report in July 2017 entitled "Natural Gas: Reliable and Resilient"[2] that details how the physical characteristics of our natural gas delivery system enhance its resiliency. The natural gas transportation network is made up of an extensive system of interconnected pipelines that offers multiple pathways for rerouting deliveries to maintain service in the unlikely event of a physical disruption. As was demonstrated during and after the 2017 hurricane season, natural gas systems continued to provide services (and even fuel natural gas vehicles) where other grid or electric systems were damaged, under repair, or otherwise failed.

[2] The Natural Gas Council July 2017 report entitled "Natural Gas: Reliable and Resilient" can be found at http://www.ngsa.org/download/analysis_studies/NGC-Reliable-Resilient-Nat-Gas-WHITE-PAPER-Final.pdf

As you are aware, the United States leads the world in natural gas production. Natural gas production occurs across the U.S., rather than just one specific area. This diversity in domestic supply makes natural gas a very nimble domestic commodity, able to adapt to different market events, changing demand dynamics, and extreme weather events. Natural gas has increasingly become a reliable source of domestic energy over the past decade, whereas other energy prices and supplies have fluctuated. Natural gas is poised to provide stable, resilient, low cost energy for the foreseeable future and the nation should take advantage of this resource by assuring appropriate diversity of fuel consumption to minimize future risks from fuel supply disruptions.

Increasingly, the economic profile of the electric transmission and distribution market is shifting. Grid maintenance and expansion costs are rising at a rapid rate and massive investments are needed to meet future generation supply as the system transitions to a grid reliant on distributed and renewable resources. Efficiency gains no longer come from increasing generating capacity, but from smaller units located closer to sites of demand. Distributed generation reduces the amount of energy lost in transmitting electricity because the electricity is generated very near where it is used, perhaps even in the same building. This also reduces the size and number of power lines that must be constructed. One way natural gas can contribute in this space is through combined heat and power (CHP) equipment. CHP equipment are small, mass-produced appliances that may be deployed in a wide range of applications. They have a low pollution profile which means they can be placed in suburban and urban areas without impacting local air quality. Because of their proven track record in extreme weather, CHP units have become an important part of growing and developing resilient micro-grids. In fact, the federal government has been installing CHP equipment at military bases as well as other critical government operation centers.

APGA believes that any infrastructure discussion must include assessing the benefits of direct use of natural gas, a domestic resource, and evaluating how best to assure a resilient energy system, not just a resilient electric system. Preserving fuel diversity is essential to the reliability, resiliency, and security of the nation's energy system. In considering the reliability of the electric grid, Congress should take into account how low priced, domestic natural gas has changed the energy sector. APGA believes that the direct use of natural gas can and should play an important role in providing consumers a reliable, diverse, resilient and secure energy system now and well into the future. We stand ready to work with the Committee on these and all other natural gas issues.

N A R U C

National Association of Regulatory Utility Commissioners

February 22, 2018

The Honorable Lisa Murkowski
U.S. Senate
Chairman
Committee on Energy and Natural Resources
Washington, D.C. 20510

The Honorable Maria Cantwell
U.S. Senate
Ranking Member
Committee on Energy and Natural Resources
Washington, D.C. 20510

RE: February 8, 2018, Senate Committee on Energy and Natural Resources Hearing on Energy Infrastructure

Dear Chairman Murkowski and Ranking Member Cantwell:

During the hearing conducted by the U.S. Senate Committee Energy and Natural Resources on February 8, 2018, titled "The Evolution of Energy Infrastructure in the United States and How Lessons Learned from the Past Can Inform Future Opportunities," there was discussion of the Public Utility Regulatory Policies Act of 1978 (PURPA). On behalf of the National Association of Regulatory Utility Commissioners (NARUC), I respectfully request that these comments regarding PURPA be included in that record.

NARUC is a non-profit organization founded in 1889. Our members are the public utility commissions in all 50 States, the District of Columbia, and the U. S. territories. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Our members regulate the retail rates and services of electric, gas, water, and telecommunications utilities. We are obligated under the laws of our respective States to assure the establishment and maintenance of essential utility services as required by public convenience and necessity and to ensure that these services are provided under rates, terms, and conditions of service that are just, reasonable, and non-discriminatory.

NARUC encourages legislative and regulatory efforts to update and reform PURPA. Specifically, we would support reform of PURPA in ways that would address: the mandatory purchase obligation so that State utility commissions could better protect their ratepayers; modernizing the nondiscriminatory access provisions; and reform of the so-called "one-mile-rule."

In 1978, Congress enacted PURPA in response to a national energy crisis. PURPA's purpose was to promote the development of renewable energy and cogeneration technologies, as competitive alternatives to oil and other scarce sources of fuel. To do this, PURPA required electric utilities to purchase power produced by qualifying facilities (QFs), a requirement referred to as the *mandatory purchase obligation*.

PURPA mandated these power sales at a utility's *avoided cost*, which conceptually meant consumers would pay no more and no less for PURPA resources than they would for non-PURPA alternatives. However, the Federal Energy Regulatory Commission (FERC) has long held that PURPA requires that States forecast a utility's avoided cost into the future for the purpose of offering QFs a long-term contract at administratively determined rates.[1] This type of administrative pricing essentially requires States to

[1] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, 12,218, 12,224 (Feb. 25, 1980); FERC Stats. & Regs. ¶ 30,128, *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part & vacated in part sub nom. Am. Elec. Power*

guess at future market prices, allowing QFs to lock in rates that often substantially overstate the actual avoided cost. This approach is fundamentally different when compared to procurements that use competitive mechanisms like auctions or requests for proposals to discover the least-cost resource.[2] It is almost universally acknowledged that a competitive process, where generators with a profit motive vie against one another for the business of the nation's consumers, is a best practice when compared with prices set by a State commission through a trial-like proceeding where the cost-reducing aspect of competition is absent.

In addition to the flaws underlying so-called avoided-cost pricing, PURPA's mandatory purchase obligation is a poor match for the relatively flat, and sometimes even declining, customer demand for electricity. In many parts of the United States, new power plants of any kind may simply not be needed—a testament in large part to the increasing efficiency of residential and commercial appliances that previously drove demand. Yet unneeded power plants are in some places nevertheless being brought online due to PURPA's mandatory purchase obligation, a legal provision which suggests that utilities must buy from QFs even when their consumers do not need additional energy supply. As one utility noted in a filing to the Wyoming Public Service Commission, QFs had requested pricing for 4,563 MWs of supply even while its integrated resource plan indicated "no need for any system resource until 2028."[3] In sum, PURPA's flawed approach to administrative pricing and its mandatory purchase obligation is harming consumers; ironically, it is at odds with the values of competition and conservation that are at the heart of PURPA itself.

PURPA is nearly four decades old, and it reflects the reality of another era when renewables were scarce, demand was booming, and the country looked for ways to diversify its energy portfolio and shield itself from overreliance on foreign sources of supply. Today, the world has changed dramatically. The U.S. Energy Information Administration reports that *nearly half* of utility-scale capacity installed in 2017 came from renewable resources.[4] More than half of the States have their own renewable mandates, and even those which do not have shown substantial additions in renewables, not because of PURPA, but because of the falling cost curve of renewable technologies such as solar and wind.[5]

Serv. Corp. v. FERC, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

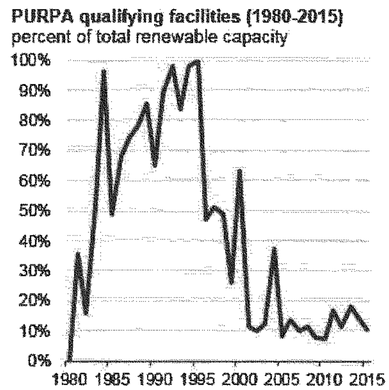
[2] State attempts to use competitive processes to comply with PURPA have been found unlawful. Most recently, California's use of a reverse-auction process to identify avoided-cost, awarding the lowest-bidders contracts, was declared invalid by a federal district court. *Winding Creek Solar LLC v. Michael Peevey, et al.*, Case 3:13-cv-04934-JD (N.D. Cal.) at 14 (Dec. 6, 2017).

[3] Application, *In the Matter of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities* (Aug. 26, 2015), Wyoming PSC Docket No. 20000-481-EA-15, p. 9.

In December 2017, Rocky Mountain Power filed an update reporting that more than 1,600 MWs of QFs had proposed online dates in 2018, 2019, and 2020. "Semi-Annual Qualifying Facility Queue Compliance Report," (Dec. 27, 2017), Wyoming PSC Docket No. 20000-481-EA-15.

[4] U.S. Energy Information Administration, *Nearly half of utility-scale capacity installed in 2017 came from renewables*, "Today in Energy (Jan. 10, 2018)," (Form EIA-860M, Preliminary Monthly Electric Generator Inventory), available online at: https://www.eia.gov/todayinenergy/detail.php?id=34472.

[5] U.S. Energy Information Administration, *PURPA qualifying facilities as a percentage of total renewable capacity* (1980-2015), "Today in Energy (Aug. 23, 2015)," available online at: https://www.eia.gov/todayinenergy/detail.php?id=27632.



To the degree that PURPA was enacted at a time when renewable technologies were not the norm, that norm has changed profoundly. There has been another significant transition, too: Nearly all States today require power generation to be procured through competitive means. Even in States that do not have consumer choice, monopoly utilities are typically required to procure resources through competitive solicitation. In short, other events have transpired that have accomplished PURPA's twin goals of advancing QF technologies and introducing competition into the sector, rendering PURPA itself largely needless.

Congress has recognized previously that as the sector changes, so too must PURPA.[6] Since its last revision of PURPA more than a decade ago, the electric industry has undergone an arguably more profound transition than it did from the time of PURPA's enactment to the Energy Policy Act of 2005 (EPAct '05). That is why the moment is ripe for your consideration of reforming and modernizing PURPA in a way which builds on the successes of EPAct '05 by encouraging competition as a means toward renewable development.

As stated previously, NARUC believes that three areas of PURPA need to be addressed. First, and most importantly from our perspective, is the mandatory purchase provision. This provision ought to be amended to acknowledge that a competitive process should be allowed to substitute for PURPA's mandatory purchase obligation using administrative-forecast pricing. QFs could be protected by tying applicability specifically to a requirement for competitive processes to be open to PURPA resources. Consumers, meanwhile, could be protected by only having to pay for resources that had offered the least cost, or the greatest value. Similarly, any legislative language ought to acknowledge those occasions, caused by flat or declining demand, when utilities have greater supply than demand. This would hew to PURPA's original principle of conservation by not requiring consumers to pay for the construction of new power plants that simply are not needed.

Second, modernizing the nondiscriminatory access provisions of PURPA is now necessary. Very small resources may not have the ability, because of either market rules or because of the transaction costs associated with participating in such markets, to sell their energy and capacity efficiently into the existing

[6] *See* Energy Policy Act of 2005 § 1253, 16 U.S.C.A. § 824a-3(m) (2017). These statutory changes, together with FERC's implementing regulations, recognized that the emergence of regional transmission organizations (RTOs) that ran competitive wholesale auctions was achieving PURPA's goals through more efficient means.

competitive markets. However, the current exemption of 20 MW badly overstates the size threshold.[7] A provision limiting the exemption to 2.5 MW is more in line with the realities of modern power generation, where smaller resources are being developed and encouraged to participate in competitive wholesale markets. Seemingly all such markets have size thresholds smaller than 2.5 MW, so such a size conservatively and fairly provides a threshold that protects smaller QFs while encouraging competition among larger projects.[8]

Third, legislation needs to addresses an enduring problem where a single developer strategically disaggregates a project into multiple QFs. Larger projects might have to participate in a competitive solicitation, because they are larger than the 80 MW that PURPA defines as the maximum capacity for a QF, so developers sometimes will break such projects into several QFs to avail each of the mandatory purchase obligation at an administrative-forecast rate. Similarly, a developer might break one larger project into several small QFs so to enter into standard-offer contracts available only to smaller QFs, which tend to be more lucrative. This regulatory arbitrage is a form of gaming that ultimately disadvantages consumers. It represents an attempt by certain QFs to avoid competition by safe-harboring themselves in what has been called the "one-mile rule," as FERC's determination that a bright-line of one mile's distance qualifies projects as separate QFs.[9] Legislation should allow for a fact-dependent investigation by FERC to police such abuse.

Thank you for giving NARUC an opportunity to present our views on the current state of PURPA. We have reached out to our FERC colleagues on some of these issues; however, we believe legislation is necessary to provide us with the ability to secure a reliable and affordable energy future for the nation. We look forward to working with this Committee on meaningful PURPA reform legislation.

Sincerely,

Greg R. White
Executive Director, NARUC

CC: All Members of the Senate Committee on Energy and Natural Resources

[7] 18 CFR § 292.309(d)(1) (2017).
[8] "Considerations for Minimum Resource Size Threshold in the Capacity Market," (July 2017), Alberta Electric System Operator, citing to CAISO, NEISO, NYISO, and PJM size thresholds at p.3. Available online at: https://www.aeso.ca/assets/Uploads/20170704-Eligibility-Session-3-Minimum-Resource-Size-Presentation.pdf.
[9] 18 C.F.R. § 292.204(a)(2) (2017).

National Hydropower Association
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February 14, 2018

The Honorable Lisa Murkowski
Chairman
Energy and Natural Resources Committee
United States Senate
Dirksen Senate Office Building
Room 304
Washington, DC 20510

The Honorable Maria Cantwell
Ranking Member
Energy and Natural Resources Committee
United States Senate
Dirksen Senate Office Building
Room 304
Washington, DC 20510

Re: Statement for the Record of the National Hydropower Association (NHA) on the February 8, 2018 hearing on energy infrastructure

Chairman Murkowski and Ranking Member Cantwell:

The National Hydropower Association (NHA) is pleased to have this opportunity to submit comments to the Committee on the fundamental importance of addressing hydropower infrastructure investment needs this year.

In addition to these comments, NHA incorporates by reference our testimony to the Committee at the March 2017 hearing on opportunities to improve American energy infrastructure and our statement for the record on the December 2017 hearing to examine the permitting processes at DOI and FERC for energy and resource infrastructure projects.[1]

NHA believes energy project deployment and project reinvestment, particularly in the hydropower, pumped storage and marine energy sectors, is a critical conversation to have in the infrastructure debate.

Today, hydropower is the largest renewable energy generation resource in the United States.[2] Over its lifetime, the existing hydropower fleet has stimulated an investment of tens of billions of dollars and created hundreds of thousands of good-paying jobs and economic opportunities and growth in localities across the country. In fact, the Department of Energy estimates that the industry currently supports approximately 120,000 jobs, which span professions from engineers and electricians, to biologists, hydrologists and cultural resource specialists, to machinists, welders and

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[1] https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=E3BD2A82-1B13-4B5F-8754-46C181EACB60. March 14, 2017.
https://www.hydro.org/wp-content/uploads/2018/02/NHA-Statement-for-the-Record-on-the-12.12.17-ENR-Hearing.docx.pdf. December 20, 2017.

[2] Business Council for Sustainable Energy and Bloomberg New Energy Finance Sustainable Energy in America Factbook 2018, P. 21. Publication pending. This despite recent modest incremental growth in capacity in recent years and wind capacity exceeding that of hydropower for the first time in 2017.

metal fabricators. A total of up to 195,000 jobs are supported if the Vision's 50 GW by 2050 growth scenario is met.[3,4]

These economic benefits are amplified by the positive environmental attributes that affordable, reliable, renewable hydropower brings to the U.S. grid; such as cleaner, healthier air as well as lower carbon emissions. Finally, hydropower infrastructure provides many other public benefits including: water supply; flood control; drought mitigation; irrigation; recreation; and navigation.

Yet, these benefits are under direct threat by a series of policy decisions (both at the federal and state levels) that undervalue and handicap our hydropower resources. These include: an outdated, complex regulatory process that takes years longer than that of any other energy resource; tax policy that picks winners and losers, often leaving hydropower at a competitive disadvantage; the lack of market policies that adequately compensate hydropower and pumped storage projects for the grid benefits and ancillary services they provide; the lack of reinvestment in the federal hydropower system; and more.

With over 400 existing projects coming up for relicensing by 2030, many of the asset owners face a difficult economic decision whether to continue operations. Already, industry members are announcing project closures, particularly small hydropower projects. [5]

And this environment also impacts new project development. While the U.S. hydropower industry, along with the nascent marine energy sector, has the capacity to grow significantly, project developers report many investors are choosing to invest in other forms of generation with far shorter process timelines and clearer risk assessments.

This Committee has been focused and working diligently over the last 4 years to address one of the main obstacles for investment in hydropower – the licensing and relicensing approval process. We continue to support the work of the Committee to implement commonsense improvements to the hydropower licensing scheme. Without addressing these regulatory challenges, hydropower will continue to struggle to compete versus other energy options, particular wind, solar and natural gas, that can be permitted in half the time.

Any debate on infrastructure should include a discussion of how regulatory improvements can be included to unlock the potential in the hydropower industry and move new projects and existing project reinvestment forward, which will create significant local economic and jobs opportunities. Currently, the Committee has several pieces of bipartisan hydropower licensing

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[3] https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-Executive-Summary-10212016.pdf. Executive Summary P.23

[4] The 2016 DOE Hydropower Vision Report estimates upward of 50 GW on new capacity in conventional hydro and pumped storage projects is possible. https://energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source

[5] http://www.hydroworld.com/articles/2017/02/pg-e-announces-it-will-not-relicense-26-4-mw-desabla-centerville-hydro-facility.html. http://klpd.org/vertical/sites/%7B423355D4-5FDE-44B4-800E-406FA53C5BD4%7D/uploads/Notice_of_Intent.pdf

legislation before it, including those provisions in S. 1460, the comprehensive energy bill, and other bills that have passed the House or Representatives, such as H.R. 3043.

We continue to strongly support these bills and urge that they be adopted this year, whether that be through action on a comprehensive energy bill, individual bills, or inclusion as part of an infrastructure package. **Investment in hydropower is an investment in a critical piece of our nation's infrastructure.** As such, we encourage the Committee to consider any legislative vehicle, including an infrastructure bill, as a pathway to achieving these licensing improvements.

With the recent passage of the Bipartisan Budget Act of 2018. NHA also wants to highlight the ongoing disparity of treatment of hydropower versus other renewable energy technologies. The Act included only a one-year retroactive extension of the hydropower and marine energy tax credits through 2017, which provides no certainty for project developers seeking to finance their projects right now. Coupled with the fact that the Congress has extended for several years the tax credits for other renewable resources (wind, solar, fuel cells, etc.), the hydropower industry is put at a severe economic disadvantage.

At a time when we are seeking ways to strengthen grid reliability and resiliency, why would Congress seek to disadvantage a premier flexible renewable baseload technology like hydropower? This isn't just playing renewable energy favorites, it's fundamentally missing hydropower's role, and the benefits it brings, to our nation's electricity grid.

If Congress' goal is an all-of-the-above energy policy, the hydropower licensing process and recent tax policy decisions fail to advance it. Hydropower has significant new growth potential as well as re-investment opportunities in existing projects. However, inaction on the policies to support the industry make it more difficult to bring new hydropower generation online and create the good-paying jobs and local economic opportunities that come with it.

Once again, we thank for your leadership on these issues facing the hydropower industry. We look forward to working with you and your staff further to advance and adopt these critical policy improvements in 2018.

Sincerely,

Linda Church Ciocci

Linda Church Ciocci
Executive Director

spire

formerly The Laclede Group

Spire Inc.
700 Market Street
St. Louis, MO 63101

February 8th, 2018

The Honorable Lisa Murkowski and Honorable Maria Cantwell
Senate Committee on Energy and Natural Resources
304 Dirksen Senate Building
Washington, DC 20510

Subject: February 8th, 2018 Full Committee Hearing on Energy Infrastructure

Introduction

Spire Inc. ("Spire") is a holding company with 3,300 employees providing natural gas to 1.7 million customers across Missouri, Mississippi and Alabama. Spire's essential messages for this committee are that:

1. Diversity is key to energy reliability and resiliency.
2. Natural gas, as an alternative to electricity at the point-of-use, should not be overlooked for what it presently contributes to energy affordability, reliability and resiliency.
3. These contributions can be readily and economically increased relative to electricity.

Spire is appreciative of this Committee's recent emphasis upon a diverse "all the above" energy policy that also seeks to safeguard affordability and reliability. However, the focus of the "all the above" discussion seems to apply only to the diversity of energy sources used for electric generation. If diversity of electricity primary energy sources is desirable, so should energy alternatives to electricity be desirable. This would best serve consumer interests. Alternatives to electricity at the point of consumer use supports the reliability of electricity generation and delivery by reducing demands and strains on the electricity system. For these reasons and as further explained below, Spire asks this Committee to consider our comments and include us in future hearings.

How Natural Gas Direct Use Adds Reliability to the Electricity System

The inherently reliable and resilient attributes of natural gas transmission and distribution ((T&D) systems were recently validated by an MIT study titled "Interdependence of the Electricity Generation System and the Natural Gas System and Implications for Energy Security"[1] as shown by the following excerpt:

[1] https://www.serdp-estcp.org/content/download/19069/208608/file/TR-1173.pdf

> *The natural gas network has few single points of failure that can lead to a system-wide propagating failure. There are a large number of wells, storage is relatively widespread, the transmission system can continue to operate at high pressure even with the failure of half of the compressors,* ***and the distribution network can run unattended and without power****. This is in contrast to the electricity grid, which has, by comparison, few generating points, requires oversight to balance load and demand on a tight timescale, and has a transmission and distribution network that is vulnerable to single point, cascading failures.* (emphasis added)

Another recent report titled Natural Gas Systems: Reliable & Resilient (from the Natural Gas Council)[2] included similar reliability findings for the natural gas T&D system as shown by the following excerpts:

> *This was demonstrated on January 7, 2014 during a "polar vortex" weather event that stretched across large parts of the United States and caused total delivered gas nationwide to reach an all-time record of 137.0 Bcf in a single day. Despite the unprecedented performance levels required, the industry honored all firm fuel supply and transportation contracts.*
>
> *The joint [FERC]-NERC Southwest Cold Weather Report made similar findings about the reliability of the natural gas system during another weather-related event. In the first week of February 2011, the southwest region of the United States experienced historically cold weather that resulted in significant impacts on the electric system in Texas, New Mexico and Arizona, and natural gas service disruptions in those states as well. During the 2011 Southwest outages, 50,000 retail gas customers experienced curtailments when gas pressure declined on interstate and intrastate pipelines and local distribution systems due to the loss of some production to well freezing at a time of increased gas system demand. In contrast, 4.4 million electric customers were affected over the course of the same event.*

This inherent reliability was repeatedly evidenced last year during Hurricanes Harvey, Irene and Maria. Reports stated that local gas utility distribution systems remained operational as shown by the following excerpts:

- AGA Updates on Hurricane Harvey
  Excerpt:
  > *Even under all of that water, the gas distribution system in the Houston area continues to operate as designed and continues to serve all customers who can physically take service.*

- Harvey cleanup efforts for gas utilities may be cheaper than post-Sandy repairs
  Thursday, August 31, 2017 9:27 AM ET
  Excerpts:

[2] http://www.ngsa.org/download/analysis_studies/NGC-Reliable-Resilient-Nat-Gas-WHITE-PAPER-Final.pdf

CenterPoint's gas system has continued operating normally despite the storm and flooding, according to company updates.

Texas Gas Service Co., too, has service territory in southeastern Texas and also has been able to maintain normal service on its system.

Many gas utility customers depend on natural gas system resiliency during times of weather emergencies as illustrated by an excerpt from the article, How Waffle House's hurricane response team prepares for disaster:

"If we have gas for the grills, we can open," said Warner. "We tailor the menu for what we can cook. Obviously, without electricity we're not gonna have waffles, but we can bring in water and porta potties. If we don't have electricity we can bring in generators. We've had some cases that before the generator came, we were there with candle light."

Of course, natural gas can also fuel generators if a facility is so equipped. Such was the case for Hurricane Sandy, at least for those with the foresight to do so. This is well documented in news reports from the affected area.[3]

As for the electric grid, equivalent resiliency is not apparent. According the U.S. Chamber of Commerce's Global Energy Institute coverage titled Harvey's Impact on Energy Daily Update, at times during the storm between 170,000 and over 300,000 customers were without power, endangering their health and safety. This is not meant to detract from the heroic efforts of those involved with restoring electric service. Rather, it is intended to illustrate that decentralized natural gas-fueled power generation (such as CHP) lessened such negative effects from outages on electric customers.

Obviously, hurricanes are not the only weather-related emergencies that can and do significantly impact modern energy delivery systems. In August 2017, the Department of Energy (DOE) released a report titled Staff Report to the Secretary on Electricity Markets and Reliability. The term "polar vortex" was mentioned 21 times. This type of weather-related emergency is one that the direct use of natural gas (and propane) is ideally suited for alleviating.

Transitioning to an all-electric energy monoculture capable of handling a "polar vortex" via "clean" electric energy may be technically feasible but would be economically devastating. In the case of Spire's peak Winter send-out for the St. Louis region, our analyses indicate that it would take about 50,000 MW of generation capacity to replace natural gas use during such

[3]
- *How CHP Stepped Up When the Power Went Out During Hurricane ...*
- *CHP Kept Schools, Hospitals Running Amid Hurricane Sandy ...*
- *Enabling Resilient Energy Infrastructure for Critical Facilities*
- *Lessons From Where The Lights Stayed On During Sandy - Forbes*
- *Hospital Plans Ahead for Power, Serves the Community Through ...*
- *Case study: Microgrid at Princeton University | Facilities*

events. Such replacement would require Ameren Missouri (the electric utility with an overlapping service territory) to invest in either new generation infrastructure or in wholesale electric resources to supply the additional electricity demand. In addition, the costs to consumers to replace natural gas furnaces and appliances with electric equipment would be prohibitive and potentially subject to consumer rejection.

Policies Should Encourage, not Discourage, Economic and Strategic Energy Diversity

Regardless of the inherent resilience and reliability of natural gas T&D systems relative to electricity, there are many who seek to move away from the direct consumption of natural gas (and propane), or any fuel, and electrify everything from water heaters to automobiles. It is important to recognize that electrification has been and continues to be the current mission of DOE's Office of Energy Efficiency and Renewable Energy (EERE). EERE's mission statement is: "to create and sustain American leadership in the transition to a global clean energy economy." The term "clean energy" as used by EERE is not defined, but for many, "clean energy" is synonymous with renewable electric energy.

Total Electrification is a Fatally Flawed Concept

Advocates of total electrification claim that it is necessary to avoid the certain destruction of global warming. These advocates overlook the overall economic and environmental impacts of total electrification, particularly within the short time frames (20-30 years) that are often discussed, and never discuss or debate the financial impacts of doing so. The theory driving "clean energy" is "deep decarbonization," which is the phase-out of the direct consumption of fossil fuels, including natural gas.

Our economy is dependent on diverse and affordable energy. The direct consumption of natural gas provides major economic benefits as well as environmental benefits and reliability benefits. These benefits are listed as follows:

- Natural gas delivers 38% more consumer energy than electricity.[4]
- Direct use of natural gas delivers about 92% of its initial (source) energy content on average (relative to 32% for electricity).[5]
- Natural gas delivers 38% more energy for 15% of the comparable electric costs.[6]
- Natural gas appliances can significantly reduce carbon emissions relative to electric appliances and do so at much lower costs.

The following chart illustrates the economics of the carbon reductions associated with natural gas appliance use:[7]

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[4] EIA Annual Energy Outlook 2017, Energy Consumption in 2015
[5] American Gas Association 2017 Playbook
[6] EIA Electric Power Annual Table 2.3, Revenue from Sales of Electricity to Ultimate Customers
[7] Levelized Cost of Energy: Expanding the Menu to Include Direct Use of Natural Gas

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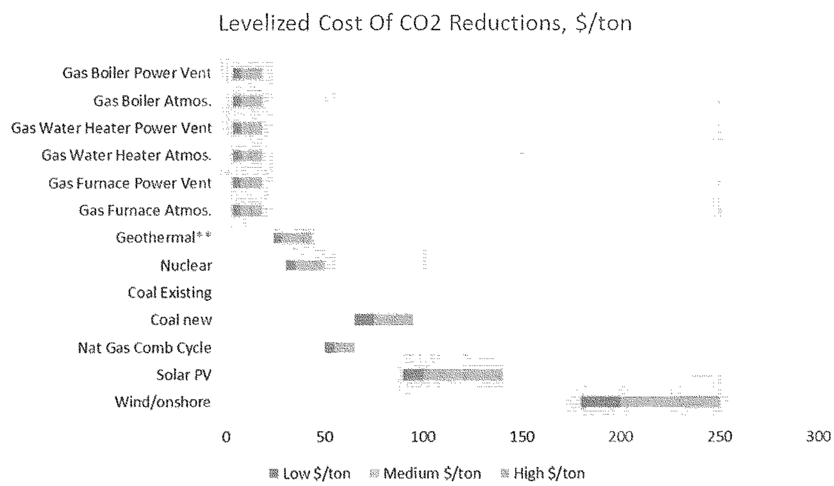

The application of the "deep decarbonization" concept should be scrutinized by energy policymakers. Congress should fully understand the economic and environmental costs to American consumers that are likely if the "deep decarbonization" path is chosen.

Simply put, for total electrification advocates, a "clean energy" economy is an all-electric economy. This concept that has not been overlooked by the electric utility industry. Growth potential from total electrification was the subject of a recent article titled EEI 2017: The utility sector's business case for deep decarbonization. The essence of this article is captured by the following excerpt:

> *"All this carbon cutting could result in a windfall for the power sector," said Sue Tierney, a principal at the Analysis Group. In her analysis of more than four dozen studies on deep decarbonization, she found that some anticipate that "electricity demand will have essentially doubled compared to where it is today as a result of those changes."*

The most significant flaw in Ms. Tierney's logic is that she appears to have seriously underestimated how much added electricity demand could increase costs by total electrification. As previously discussed, for the Saint Louis region, the additional electricity demand during peak periods that would occur if natural gas consumption is replaced will place substantial economic stress upon the upstream generation and wholesale markets and will be excessively costly to natural gas consumers.

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Summary and Conclusions

Increasing the reliability and resilience of the electric grid is important, but so too is increasing the resilience and reliability of all energy systems. Moving away from the direct use of natural gas reduces the overall system's reliability, reduces the reliability of the electric grid, casts aside the proven performance of natural gas, and increases costs to American consumers. The Committee should acknowledge natural gas direct use's contribution to reliability of both the electric grid and energy systems overall and convey that acknowledgement to DOE and other energy policymakers.

Spire requests that the Committee schedule follow-up hearings to addresses broader issues that include the cost effectiveness and risks associated with alternative means of ensuring energy system reliability for energy consumers and our economy.

Should the Committee need more specific information, please contact:

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Sincerely,

Mark C. Darrell

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