EXAMINING THE STATE OF ELECTRIC TRANSMISSION INFRASTRUCTURE: INVESTMENT, PLANNING, CONSTRUCTION, AND ALTERNATIVES

HEARING
BEFORE THE
SUBCOMMITTEE ON ENERGY
OF THE
COMMITTEE ON ENERGY AND COMMERCE
HOUSE OF REPRESENTATIVES
ONE HUNDRED FIFTEENTH CONGRESS
SECOND SESSION
MAY 10, 2018
Serial No. 115–127
### CONTENTS

Hon. Fred Upton, a Representative in Congress from the State of Michigan, opening statement ............................................................... 1  
Prepared statement ........................................................................... 3

Hon. Bobby L. Rush, a Representative in Congress from the State of Illinois, opening statement .................................................. 4

Hon. Frank Pallone, Jr., a Representative in Congress from the State of New Jersey, opening statement ............................................ 5

Hon. Greg Walden, a Representative in Congress from the State of Oregon, prepared statement .................................................. 112

### WITNESSES

Tony Clark, Senior Advisor, Wilkinson Barker Knauer, LLP .................. 7
Prepared statement ........................................................................... 10
Answers to submitted questions ......................................................... 118

Edward Krapels, CEO, Anbaric Development Partners ......................... 32
Prepared statement ........................................................................... 34
Answers to submitted questions ......................................................... 124

Jennifer Curran, Vice President, System Planning, Midcontinent ISO .... 45
Prepared statement ........................................................................... 47
Answers to submitted questions ......................................................... 130

Ralph Izzo, CEO, Public Service Enterprise Group, Inc. ..................... 60
Prepared statement ........................................................................... 62
Answers to submitted questions ......................................................... 137

John Twitty, Executive Director, Transmission Access Policy Study Group .. 70
Prepared statement ........................................................................... 72
Answers to submitted questions ......................................................... 142

Rob Gramlich, President, Grid Strategies, LLC ..................................... 86
Prepared statement ........................................................................... 88
Answers to submitted questions ......................................................... 152

### SUBMITTED MATERIAL

Statement of GridLiance ....................................................................... 114
Statement of WIRES ............................................................................ 116
EXAMINING THE STATE OF ELECTRIC TRANSMISSION INFRASTRUCTURE: INVESTMENT, PLANNING, CONSTRUCTION, AND ALTERNATIVES

THURSDAY, MAY 10, 2018

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY,
COMMITTEE ON ENERGY AND COMMERCE,
Washington, DC.

The subcommittee met, pursuant to call, at 9:46 a.m., in room 2123, Rayburn House Office Building, Hon. Fred Upton (chairman of the subcommittee) presiding.


Staff Present: Samantha Bopp, Staff Assistant; Daniel Butler, Staff Assistant; Kelly Collins, Legislative Clerk, Energy/Environment; Wyatt Ellertson, Professional Staff, Energy/Environment; Margaret Tucker Fogarty, Staff Assistant; Elena Hernandez, Press Secretary; Drew McDowell, Executive Assistant; Brandon Mooney, Deputy Chief Counsel, Energy; Mark Ratner, Policy Coordinator; Annelise Rickert, Counsel, Energy; Jason Stanek, Senior Counsel, Energy; Austin Stonebraker, Press Assistant; Jeff Carroll, Minority Staff Director; Jean Fruci, Minority Energy and Environment Policy Advisor; Jourdan Lewis, Minority Staff Assistant; John Marshall, Minority Policy Coordinator; Tim Robinson, Minority Chief Counsel; C.J. Young, Minority Press Secretary.

OPENING STATEMENT OF HON. FRED UPTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Mr. UPTON. We are going to get started on time. I just want to let folks know that our committee has a pretty major bill on the House floor this morning, a bill that passed out of committee 49 to 4, on nuclear waste.

I know that debate there has started. A number of us have been there already to speak. And our colleague, John Shimkus, is helping to manage that bill. So I am not sure that he will be back. But we are expecting votes about 10:45, so I am going to try to be quick with the gavel. And we will continue after that, but it will be a series of votes.

Good morning. Today we are continuing our Powering America series by taking a closer look at a very important but often under-
appreciated component of our power sector: the electric transmission system. Ever since visionaries such as Edison, Tesla, and Westinghouse argued the merits of using direct current versus alternating current, the manner and means by which electricity is delivered has been a complicated and, yes, controversial topic.

We depend on our high voltage network of wires and cables to transmit electricity long distances to power everything from our iPhones to our economy. A stable and uninterrupted supply of electricity is critical to ensure the public's health and safety, as well as the quality of life that we have come to expect. However, in many parts of our country our transmission infrastructure, like our Nation's roads and bridges—particularly if you are in Michigan—is aging, congested, and in need of repair or replacement.

Joining us today is a distinguished panel of experts to help us better understand the challenges that the electric transmission sector is facing, as well as the opportunities that may be within reach.

While much of this debate in the industry is currently focused on generator resilience and fuel security, we cannot ignore the vital role that the Nation's electric transmission infrastructure plays in connecting the electricity producer to the end-use consumer. And as such, I would argue that a resilient and reliable transmission grid is no less important.

Transmission infrastructure, however, does not come cheap, and the planning and construction of new lines often takes years due to permitting and environmental reviews. Over the past couple of years, public utilities and independent transmission developers have committed over $20 billion annually to upgrade or replace our existing transmission infrastructure. And while that is good news, creating jobs, et cetera, sustained investment at similar levels will be critical to ensure that Americans have a modern electricity grid that can deliver reliable power at a reasonable cost.

In addition, a predictable regulatory environment and consistent policies regarding how transmission projects are approved and paid for is essential to reduce financial risk and attract new capital. After we passed the Energy Policy Act of 2005, FERC was directed to encourage investment in transmission infrastructure projects that reduce the cost of delivered power by reducing congestion on the grid. FERC responded by granting financial incentives to transmission proposals that met certain criteria. And in subsequent years FERC began to issue a series of landmark rules to oversee and regulate the details of how transmission projects are planned, paid for, and ultimately developed.

Order 1000 is the agency's most recent attempt to regulate regional and interregional transmission planning, while also encouraging competition between transmission developers. However, as we heard from witnesses in our earlier Powering America hearings, while some regional transmission planning processes have become more effective, Order 1000 has all but failed to develop new lines between and among RTOs and other planning regions. Moreover, FERC's rule allowing merchant developers to now compete against traditional utilities to build transmission projects has been criticized as ineffective for a number of reasons. With the help of our witnesses, we will explore these and other challenges associated with transmission planning, cost allocation, and competition.
Finally, I hope that we can discuss how alternatives to transmission lines factor into the conversation. While high-voltage wires form the backbone of our smart-grid technologies, demand response, energy storage, distributed generation, and microgrids can also provide benefits similar to traditional transmission. Since these alternatives may improve reliability while reducing environmental impacts and cost to consumers, we should explore whether any legal or regulatory barriers stand in the way to prevent energy innovation from reaching its full potential.

So we look forward to hearing from our witnesses.

I yield the balance of my time to my good friend and colleague on the subcommittee, Mr. Long from Missouri.

[The prepared statement of Mr. Upton follows:]

PREPARED STATEMENT OF HON. FRED UPTON

Good morning. Today, we are continuing our Powering America series by taking a closer look at a very important, but often under-appreciated component of our power sector: the electric transmission system. Ever since visionaries such as Edison, Tesla, and Westinghouse argued the merits of using direct current versus alternating current, the manner and means by which electricity is delivered has been a complicated and controversial topic.

We depend on our high voltage network of wires and cables to transmit electricity long distances to power everything from our iPhones to our economy. A stable and uninterrupted supply of electricity is critical to ensure the public’s health and safety, as well as a quality-of-life that we have come to expect. However, in some parts of the country, our transmission infrastructure, like our nation’s roads and bridges, is aging, congested, and in need of repair or replacement. Joining us today is a distinguished panel of experts to help us better understand the challenges that the electric transmission sector is facing, as well as the opportunities that may be within reach.

While much of the debate in the industry is currently focused on generator resilience and fuel security, we cannot ignore the vital role that the nation’s electric transmission infrastructure plays in connecting the electricity producer to the end-use consumer. As such, I would argue that a resilient and reliable transmission grid is no less important.

Transmission infrastructure, however, does not come cheap, and the planning and construction of new lines often takes years due to permitting and environmental reviews. Over the past few years, public utilities and independent transmission developers have committed over $20 billion annually to upgrade or replace our existing transmission infrastructure. While this is good news, sustained investment at similar levels will be critical to ensure that Americans have a modern electricity grid that can deliver reliable power at a reasonable cost.

In addition, a predictable regulatory environment and consistent policies regarding how transmission projects are approved and paid for is essential to reduce financial risk and attract new capital. After we passed the Energy Policy Act of 2005, FERC was directed to encourage investment in transmission infrastructure projects that reduce the cost of delivered power by reducing congestion on the grid. FERC responded by granting financial incentives to transmission proposals that met certain criteria. In subsequent years, FERC began to issue a series of landmark rules to oversee and regulate the details of how transmission projects are planned, paid for, and ultimately developed.

Order 1000 is the agency’s most recent attempt to regulate regional and inter-regional transmission planning while also encouraging competition between transmission developers. However, as we heard from witnesses in our earlier Powering America hearings, while some regional transmission planning processes have become more effective, Order 1000 has all but failed to develop new lines between and among RTOs and other planning regions. Moreover, FERC’s rule allowing merchant developers to now compete against traditional utilities to build transmission projects has been criticized as ineffective for several reasons. With the help of our witnesses, we’ll explore these and other challenges associated with transmission planning, cost allocation, and competition.

Finally, I hope that we can discuss how alternatives to transmission lines factor into the conversation. While high-voltage wires form the backbone of our grid—
smart technologies; demand response; energy storage; distributed generation and microgrids can provide benefits similar to traditional transmission. Since these alternatives may improve reliability while reducing environmental impacts and costs to consumers, we should explore whether any legal or regulatory barriers stand in the way to prevent energy innovation from reaching its full potential.

There's no question that as the nation's electric industry changes, the demands placed upon our existing transmission infrastructure will only increase with time. Today, our focus will be on how the industry and government can plan for the future to ensure that our power grid is ready to meet the needs of the 21st century. Thank you to the witnesses for agreeing to be with us today and I look forward to your testimony.

Mr. LONG. Thank you, Mr. Chairman.

I just want to take a few seconds here to personally introduce one of the witnesses that is here today with us, a fellow that I have known since grade school, and fraternity brothers in college, and on through life. And that would be one Mr. John Twitty.

John is the former CEO of City Utilities in Springfield, in my home district, and he now serves as executive director of the Transmission Access Policy Study Group, TAPS.

Welcome, John. And I want to thank you for lending your expertise to this hearing. Welcome to D.C.

Mr. UPTON. The gentleman yields back.

I recognize for an opening statement my friend and colleague, the ranking member of the subcommittee, Mr. Rush from Chicago, Illinois.

OPENING STATEMENT OF HON. BOBBY L. RUSH, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

Mr. RUSH. I want to thank you, Mr. Chairman.

And I want to welcome the witnesses to the hearing today.

Today we will be examining the state of electric transmission infrastructure.

As you know, Mr. Chairman, there have been many developments in the Nation's energy portfolio since FERC issued Order No. 890 back in 2007 as a way to promote open-access transmission services. This rule outlined a planning process for transmission providers consisting of nine planning principles, including coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

In 2011, Mr. Chairman, FERC issued Order No. 1000 as a way to further improve the planning process within and among geographic regions and also to determine how transmission costs were distributed to customers. Order 1000 was also issued to provide additional opportunity for non-incumbent transmission developers to compete to build projects within the service territory of incumbent utilities.

Mr. Chairman, in reviewing this policy it appears that the results have been mixed in regards to how successful it has been in achieving its goals. We are in the midst of a rapidly changing energy landscape, reflected in part by the emergence of renewable energy sources, low-cost natural gas, State-led Renewable Portfolio Standard goals, as well as an increase in energy-efficiency initiatives and overall reductions in energy demand.
Mr. Chairman, shifting consumer behavior is driving many of these changes as customers demand cleaner forms of energy along with new tools to more responsibly use the energy they consume, both as a way to save money and as a way to save the environment.

Traditional methods of buying and selling energy are being disrupted by demand response programs where emerging technologies, such as energy storage and distributed-energy systems, allow consumers to produce energy and sell it back to the grid.

Mr. Chairman, based on the testimony that we will hear today, it appears there are some real concerns with Order 1000, and modifications may be needed to help meet its objectives. If the goal was to provide a clear and collaborative inter- and intraregional planning process, with transparent and fair cost allocations, in order to spur additional competition and increased investment in grid infrastructure projects, then it is less clear if that objective had been achieved.

While most of the witnesses believe that changes should be made, there is less consensus on what those changes should look like.

So I look forward to engaging the panel today, Mr. Chairman, regarding the opportunities and the challenges surrounding Order 1000, as well as recommendations for improving this policy.

With that, I yield back.

Mr. Olson [presiding]. Thank you.

The chairman of the full committee, Mr. Walden, is not here. So the chair now calls upon the ranking member of the full committee, Mr. Pallone, for a 5-minute opening statement.

OPENING STATEMENT OF HON. FRANK PALLONE, JR., A REPRESENTATIVE IN CONGRESS FROM THE STATE OF NEW JERSEY

Mr. Pallone. Thank you, Mr. Chairman.

I want to welcome our excellent panel of witnesses.

In particular, I am pleased we have Ralph Izzo, the President and CEO of PSE&G here today. Ralph and I have worked together and known each other for many years, and I value his opinion and appreciate the service that PSE&G provides to my constituents and to our State of New Jersey.

The network of transmission lines are truly the backbone of the power system, and these transmission lines are critical to providing reliable electricity. But just like any large, conspicuous infrastructure project, transmission projects are rarely free from controversy. And in densely populated areas, such as we have in the Northeast, allocating space for any new infrastructure is often a challenge.

The electricity sector is undergoing tremendous change. There are new technologies in growth and distributed generation. At the same time, demand for power has remained relatively flat. And there are new challenges of extreme weather and cybersecurity threats, along with increasing demand for the grid to be more flexible and responsive. And all these things require us to evaluate the policy tools that FERC is using to manage its evolution.

We will hear a variety of opinions today about the degree to which FERC’s orders are helping or hindering investments in elec-
tric transmission. It is a challenge to get this balance right, so it is no surprise that stakeholders in this arena will have diverse opinions on how to improve these policies.

If we look at the map of existing transmission lines across the country, it is hard for me to believe that we need a lot of new transmission. This is a very mature network. But since much of that network has been in place for decades, it is also a good bet that it needs to be upgraded and modernized.

This is something that companies must consider when they are pursuing a transmission project. And a project in my own district, the Monmouth County Reliability Project proposed by FirstEnergy, is one example where there was no serious consideration given to nontransmission options that could make the area's system more resilient and reliable.

It was only through the diligent efforts of a group of my constituents called the Residents Against Giant Electric, or RAGE, that this expensive, unnecessary project is not moving forward. RAGE provided expert analysis demonstrating that transmission alternatives could be accomplished or an upgrade to the grid at a far lower cost to ratepayers and that these alternatives were never seriously considered. The administrative law judge who reviewed the case in Monmouth County agreed with that assessment.

This project in my home district illustrates that there remains a bias to building transmission rather than using new tools. It is in the financial interest of transmission companies to build, especially when there are clear rules that allow them to recoup those investments.

Determining if new transmission is needed must involve all stakeholders and be evaluated without bias. If, in fact, new transmission lines are needed, and in some cases they will be, then the project should go forward. But where new technology can provide a cheaper solution that is less disruptive to other businesses, existing infrastructure, and communities, we should ensure that those options are used.

So, again, the rapidly changing environment we are in right now is both exciting and challenging. FERC's efforts to address transmission challenges have been admirable but far from perfect. There have been and will continue to be missteps along the way that require adjustment and correction, perhaps even serious revision in some areas.

And so I am hoping, Mr. Chairman, that this series of hearings is providing all of us with an opportunity to better understand where the greatest challenges remain.

And, again, I want to thank all of our witnesses, including Ralph Izzo, for appearing today. I look forward to your testimony.

I would yield back the balance of my time to the gentleman from California, Mr. McNerney.

Mr. McNerney. Well, I thank the ranking member for yielding. And as a cochair of the Grid Innovation Caucus, I am pleased to be part of this hearing.

I thank the witnesses for their testimony and look forward to working with them to create what the Presidents of both parties have called the 21st century electric grid.
Congress needs to address the requirements of an evolving grid, including advances in technology, consumer adoption of distributed generation, and increasing cyber threats to this backbone of American industry.

Just yesterday two bills sponsored by Congressman Latta and myself focused on cybersecurity passed the full committee. This hearing is an important corollary to those efforts. What investments should we be making? What regulatory regime should we be reviewing within FERC or otherwise? And what more should we be doing to modernize our grid?

I look forward to working with each of you to develop practical, commonsense proposals to creating an advanced transmission system.

And I yield back.

Mr. OLSON. Thank you.

And there are no more opening statements by members, so now it is the fun time. Our witnesses will have 5 minutes to give their brief presentations. I will work this from your right to your left. And make sure you hit the button and it comes on, and speak into the mic.

We have a former commissioner of FERC, Mr. Tony Clark, who is now a senior adviser at Wilkinson Barker Knauer.

You are up, Mr. Clark, for 5 minutes.

STATEMENTS OF TONY CLARK, SENIOR ADVISOR, WILKINSON BARKER KNAUER, LLP; EDWARD KRAPELS, CEO, ANBARIC DEVELOPMENT PARTNERS; JENNIFER CURRAN, VICE PRESIDENT, SYSTEM PLANNING, MIDCONTINENT ISO; RALPH IZZO, CEO, PUBLIC SERVICE ENTERPRISE GROUP INC.; JOHN TWITTY, EXECUTIVE DIRECTOR, TRANSMISSION ACCESS POLICY STUDY GROUP; AND ROB GRAMLICH, PRESIDENT, GRID STRATEGIES LLC

STATEMENT OF TONY CLARK

Mr. CLARK. Thank you, Mr. Chairman, members of the committee, and Ranking Member Rush. My name is Tony Clark. I am a Senior Advisor at the law firm of Wilkinson Barker Knauer, which has offices here in D.C. and in Denver, Colorado.

From 2012 to 2016, I had the honor of serving on the Federal Energy Regulatory Commission. Prior to that, I served 12 years as a commissioner and for part of the time as chairman of the North Dakota Public Service Commission. It is a particular honor to recognize my former colleague, Congressman Cramer, and a good friend of many years.

My testimony today centers on a white paper that I recently authored entitled “Order 1000 at the Crossroads.” It offers my reflections on the order, the status of it, and where it might go from there. I have attached a copy of the paper as an appendix to my testimony.

As way of background, Order 1000 was promulgated before I got on the Commission, not long before I got on the Commission, so I didn’t participate in that. But I did participate in the many compliance filings that came forward in the wake of the order.
The main thesis of my reflection is that, however well-intentioned the order is, in practice it is falling short of the lofty goals that it set. I suggest that with the passage of a better part of a decade since its adoption, now is an appropriate time for FERC and for Congress, through its oversight authority, to engage in a meaningful assessment of the order.

The paper concludes that one of the paradoxical results of the rule has been that the major transmission projects that many of us thought might come out of Order 1000 actually came out of a pre-Order 1000 world. And in the time spent since Order 1000 was promulgated, there really haven’t been a lot of tangible projects that have come through or empirical data to support the success of the order. The paper concludes that if FERC were to better tailor the rule, especially recognizing significant regional differences across the utility industry, it might have more efficacy. Put succinctly, we may today find ourselves in the position of having a rule that ensures significant compliance costs, but without a lot of demonstrable benefits coming out the other side.

It is perhaps ironic that many of the most impactful transmission projects that I mentioned, such as in my home region the MISO Multi-Value Project, arose from that pre-Order 1000 world that I talked about. I suggest that the reason for this is multifold. Some of it is that regions, particularly those that were served by vertically integrated utilities, were already doing a fair amount of planning within their regions prior to the order. For those regions, Order 1000 replaced that collaborative bottoms-up process with a Federal top-down process where there is a fair amount of bureaucracy that is involved with it. And the name of the game is making sure that you are checking compliance checklists as opposed to actually bringing projects to fruition.

Creating a Federal mandate on top of what was already previously happening with many regions has added time and complexity. And we have seen in some regions a lot of litigation with respect to the transmission projects. The electricity landscape has changed dramatically in terms of the resources, technology, and State policies that drive transmission decisions, both since EPAct 05 and Order 890, which preceded Order No. 1000. And then finally, certain implementation decisions, such as how cost allocation is handled within regions, has altered transmission development models that were previously broadly accepted within a number of the regions.

In short, even among those who are broadly supportive of Order 1000, there seems to a widespread sense that something is amiss with it in terms of the underwhelming results that have come out of it. In light of this, I would argue that it is appropriate for policymakers to consider Order 1000’s future given its track record. My paper encourages industry conversations about ways that Order 1000 could be streamlined across the board.

While regional planning conversations may result in some benefits—and I would add there may be some benefit especially when talking about interregional projects where maybe not as much conversation had happened in the past—there may be ways to do it while repealing some of the more prescriptive aspects of the order.
Briefly, moving beyond Order 1000, I would offer that I think there are a number of regulatory policy calls coming up that could have a significant impact on how transmission infrastructure will be developed. FERC has significant decisions ahead it, dealing with issues like rates of return on transmission projects for jurisdictional rates, issues related to transmission incentives that FERC builds into its rate structure.

And, finally, one of the big elephants in the room on transmission development is, as it is with pipeline development, it is very difficult to get infrastructure projects sited and brought through the construction phase because of multiple levels of sometimes bureaucracy and red tape that can block some of those permitting decisions.

With that, I conclude my testimony. Thank you. I look forward to any questions you might have.

[The prepared statement of Mr. Clark follows:]
Testimony of Tony Clark  
Senior Advisor, Wilkinson Barker Knauer, LLP  
Before the Committee on Energy and Commerce Subcommittee on Energy  
United States House of Representatives  
May 10, 2018

Chairman Upton, Ranking Member Rush and members of the committee, my name is Tony Clark. I am a senior advisor at the law firm of Wilkinson Barker Knauer LLP, which has offices in Denver, CO and Washington, DC. From 2012 until 2016, I served as a Commissioner of the Federal Energy Regulatory Commission. Prior to that, I served nearly 12 years as a state utility regulator in my home State of North Dakota. During my tenure as a state commissioner, I had the honor of completing a term as President of the National Association of Regulatory Utility Commissioners.

My testimony today centers on a recent white paper I authored entitled “Order No. 1000 at the Crossroads.” It contains my reflections on the Order, its history and its status, now close to seven years after its adoption. I have attached the paper as an appendix to my testimony.

Given my career background, which straddles both sides of the state-federal jurisdictional divide in energy policy, I have long been interested in the topic of electricity transmission policy. This is especially true coming from a region of the country which is rich in energy resources, but geographically distant to the nation’s major load centers.

By way of background, I would note that Order No. 1000 was promulgated shortly before I joined FERC, so while I did not participate in its drafting, I did have the opportunity to be involved with the many compliance filings that resulted in its wake.
The main thesis of my paper is that however well-intentioned the Order, in practice today, it is falling short of its goals. I suggest that with the passage of the better part of a decade since its adoption, now is an appropriate time for FERC to engage in a meaningful assessment of Order No. 1000. The paper concludes that one of the paradoxical results of the rule has been that major transmission projects of the kind that many thought the Order would spur came out of a pre-Order No. 1000 world. Meanwhile, the post-Order No. 1000 timeframe has been marked by bureaucracy, but few tangible projects or empirical data to indicate success for the Order. The paper concludes that FERC should better tailor the rule, especially recognizing the significant regional differences across the utility industry. Put succinctly, we may today find ourselves in the position of having a rule that entails significant compliance costs but without attendant benefits.

I surmise that part of this is the result of the lack of clear focus in the Order itself. Order No. 1000 never fully reconciled the tensions between its numerous goals. Some goals, like increasing transmission planning and investment for remote sources of generation, can conflict with other goals, like competitive developer reforms. Similarly, the Order's public policy goals may be inherently contradictory in the face of conflicting state public policies, including those policies that may discourage the building of transmission.

It is perhaps ironic that many of the most impactful transmission projects (such as the MISO "Multi Value Projects) arose from a pre-Order No. 1000 world. I suggest that the reason for this is multifold:

- Regions, especially those that are still served by vertically integrated utilities, were already doing a fair amount of regional planning before the order. For these regions,
Order No. 1000 replaced this collaborative, bottoms-up approach to transmission planning with a complex bureaucracy, where the name of the game is completing a compliance checklist that may not actually result in transmission development.

- Creating a federal mandate on top of what was previously happening within many regions has added time, complexity and litigation to transmission development.

- The electricity landscape has changed dramatically in terms of resources, technology and state policies that drive transmission decisions. Order No. 1000 was written in a post-Energy Policy Act of 2005 world that may not have yet fully appreciated the impact of things like low-cost natural gas, a proliferation of state public policies that support generation outside of traditional markets, flattening demand growth, and increasing levels of distributed energy resource penetration.

- Certain implementation decisions, such as cost allocation policies, have altered transmission development models that were previously broadly accepted within regions.

In short, even amongst those who are broadly supportive of the original Order, there is a widespread sense that Order No. 1000 is underwhelming in terms of producing results commensurate with its costs.

In light of this, I argue that it is appropriate for policy makers to consider Order No. 1000’s future given its track record.

My paper encourages industry conversations about ways that Order No. 1000 could be streamlined across the board. While regional planning conversations may result in some
benefits, there may be ways to keep those benefits without imposing the more prescriptive aspects of the order. This is especially true in the majority of all states where utilities continue to serve as vertically integrated monopolies. Furthermore, while my paper highlights that there may still be a philosophical rationale for Order No. 1000 in restructured regions of the country, I do note that even there, the implementation of the Order has raised concerns, which suggests a review in these regions is merited also.

Moving beyond Order No. 1000, I would offer that I believe there are a number of regulatory policy calls that will be made in the near future that will have a big impact on how and whether transmission infrastructure will be developed.

FERC has significant decisions ahead of it related to transmission returns on equity for federal jurisdictional rates. In addition, issues related to transmission incentives may be ripe for a review at the Commission, as are discussions about how to best utilize regulatory tools such as Construction Work in Progress (CWIP).

Finally, transmission development continues to be a difficult endeavor at many levels of government. Siting and permitting of any energy infrastructure is complex and controversial—and transmission lines have long been amongst the most challenging of these projects. While some attempts to streamline transmission siting have been made in recent years, bringing projects to fruition is still among the most difficult undertakings of energy delivery companies.
Thank you for the invitation to be with you today. I look forward to answering any questions you may have.
My testimony today centers on a recent white paper I authored entitled "Order No. 1000 at the Crossroads." The primary conclusion of the paper is that the bureaucratic requirements of Order No. 1000 outweigh its benefits, and it should be reconsidered, especially in regions of the country with vertically integrated utilities.

It is perhaps ironic that many of the most impactful transmission projects arose from a pre-

Order No. 1000 world. I suggest that the reason for this is multifold:

- Regions, especially those that are still served by vertically integrated utilities, were already doing a fair amount of regional planning before the order. For these regions, Order No. 1000 replaced this collaborative, bottoms-up approach to transmission planning with a complex bureaucracy, where the name of the game is completing a compliance checklist that may not actually result in transmission development.

- Creating a federal mandate on top of what was previously happening within many regions has added time, complexity and litigation to transmission development.

- The electricity landscape has changed dramatically in terms of resources, technology and state policies that drive transmission decisions. Order No. 1000 was written in a post-EPACT 2005 world that may not have yet fully appreciated the impact of things like low-cost natural gas, a proliferation of state public policies that support generation outside of traditional markets, flattening demand growth, and increasing levels of distributed energy resource penetration.

- Certain implementation decisions, such as cost allocation policies have altered transmission development models that were previously broadly accepted within regions.

- The order lacked a clear focus, and Order No. 1000 never fully reconciled the tensions between its numerous, sometimes conflicting, goals.

In short, even amongst those who are broadly supportive of the original order, there is a widespread sense that that Order No. 1000 is underwhelming in terms of producing results commensurate with its costs.
Order No. 1000 at the Crossroads: Reflections on the Rule and Its Future

Tony Clark

APRIL 2018

With thanks to my colleagues Michael Keegan and Robin Laut.
I. Overview

With the passage of the better part of a decade since its adoption, now is an appropriate time for the Federal Energy Regulatory Commission (FERC) to engage in a meaningful assessment of Order No. 1000. This paper concludes that one of the paradoxical results of the rule has been that major transmission projects of the kind that many thought the order would spur came out of a pre-Order No. 1000 world. Meanwhile, the post-Order No. 1000 timeframe has been marked by bureaucracy, but few tangible projects. The paper concludes that FERC should better tailor the rule to certain predominantly restructured regions of the country while substantially unburdening those regions for whom the compliance regime seems to have quickly reached a point of diminishing returns.

II. Introduction

If the success of a rule promulgated by FERC is measured solely by the amount of industry discussion and trade press coverage, then FERC Order No. 1000 has a rightful place in the pantheon of great Commission rulings. Yet today, few who follow the electricity industry would argue that Order No. 1000 comes close to having successfully achieved its stated goals in a fashion similar to previous FERC reforms like the unbundling of electric transmission or pipeline transportation. Put plainly, Order No. 1000, you're no 888 or 636.

Why has Order No. 1000 in practice never matched its hype? Why is it that many of the biggest regional transmission buildouts, the type of projects that Order No. 1000 purportedly encouraged, happened prior to Order No. 1000, while the period since its promulgation has seen relatively little transmission development? In short, even its biggest proponents must agree that Order No. 1000 somehow missed the mark, or concede that at best, its impact has been underwhelming. And with the benefit of hindsight, what lessons have we learned? That is the focus of this White Paper.

After laying out the background of Order No. 1000 and discussing the myriad of goals that the rule was meant to support, this paper identifies one of the major pitfalls of the rule: it imposes bureaucratic planning requirements on the national transmission system, largely without considering that each region’s needs, priorities, and processes are different. After reviewing some of the significant differences that exist between the regions and the changes that have occurred in the electric industry since the rule was promulgated, I ask, “Where are we and where do we go from here?”

1 Of course, Order No. 1000 is only applicable to the extent of FERC's jurisdiction over the transmission of electric energy in interstate commerce.
III. FERC Order No. 1000 Background

FERC aficionados can feel free to skip this section, but in the interest of thoroughness, I provide the basics of Order No. 1000. FERC's own website offers a concise overview of the 620 page order, its background and features of the rule. Rather than reinventing a summary, FERC's explanation is provided in its own words:

Order No. 1000 is a Final Rule that reforms the Commission’s electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.

Background
On June 17, 2010, FERC issued a Notice of Proposed Rulemaking seeking comment on potential changes to its transmission planning and cost allocation requirements. Industry participants and other stakeholders provided extensive comment in response to the Notice of Proposed Rulemaking. The Commission received more than 180 initial comments and more than 65 reply comments.

Planning Reforms
The rule establishes three requirements for transmission planning:

1. Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
3. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

Cost Allocation Reforms
The rule establishes three requirements for transmission cost allocation:

1. Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the
regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles. Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles. Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.

**Nonincumbent Developer Reforms**

Public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:

1. This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
2. This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.
3. Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.
4. The rule recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

**Compliance**

Order No. 1000 takes effect 60 days from publication in the Federal Register.

Each public utility transmission provider is required to make a compliance filing with the Commission within 12 months of the effective date of the Final Rule.

Compliance filings for interregional transmission coordination and interregional cost allocation are required within 18 months of the effective date.2

---

A reader unfamiliar with much of the history and contemporary practice of the electric utility industry would be forgiven if, after reading this summary, s/he responded with a shrug. On its surface, it really doesn’t look like much more than:

- transmission regions (including independent system operators (ISOs) and regional transmission organizations (RTOs)) should be talking amongst themselves and with each other to rationally plan the electric grid;
- regions should figure out how to pay for transmission; and
- there should be an opportunity for non-incumbent utilities to build transmission.

While the preceding description of the rule is accurate, as far as it goes, a 50,000 foot explanation of Order No. 1000 understates the more robust list of motivations that inspired it. Frankly, if those three points were all that Order No. 1000 sought to accomplish, one might think it could be done with something less than the thousands of pages of regulations that comprise Order Nos. 1000, 1000-A, 1000-B and the numerous subsequent regional compliance Orders. To better understand the policy environment that gave us the rule and its numerous subsequent compliance filings, a little more color commentary is needed. It helps explain why nearly seven years after the rule was adopted, multiple industry observers wonder why something seems amiss.

IV. The Many Goals of Order No. 1000

Depending on the audience and the person or group discussing the goals of the rule, the benefits of Order No. 1000 might variously be purported to be:

- The rule is designed to support state or federal “public policy requirements” in electricity. It should be acknowledged that, however nebulous the term, “public policy requirements,” in reality, it was often code for “supporting renewables.” However nebulous the term “public policy requirements” in reality it was often code for “supporting renewables.” It would be difficult, however, for FERC to just come out and say, “Order 1000 is promulgated to support politically advantaged renewables.” The Federal Power Act does not work like that, and FERC would have been called on the carpet in the courts had it tried it. Nonetheless, the state public policy considerations referenced in Order No. 1000 were clearly aimed at expanding transmission to support things like state renewable portfolio mandates, not expanding opportunities for coal, nuclear or natural gas powered resources. Order 1000 envisioned the building of big, interregional projects, or energy superhighways stretching from geographically distant, but renewable rich, areas to the nation’s load centers. Even more amorphous is the notion of “federal public policy requirements.” In the context of 2010, it would be reasonable to assume FERC might have written this in anticipation of the Obama Administration’s imposing of a theretofore unstated national energy policy, in all likelihood driven by carbon emissions constraints. But that never came to pass and if the nation has a coherent, stated national energy policy that lasts beyond the predilections of any given presidential administration, it would be hard to identify it.
• The rule is designed to break down the silos between utilities and amongst regions of the country. In many ways, this argument was part and parcel of the one preceding it. For example, many felt that FERC needed to facilitate the delivery of wind-generated energy from places like the sparsely-populated, wind-rich Upper Midwest and Great Plains regions (located in the MISO and SPP regional transmission organizations), to the Mid-Atlantic and Midwestern population centers located in the PJM Interconnection. To the degree silos needed to be broken down, it was because states and regions were looking to realize the benefit of moving power (presumably renewables) across broader geographic regions, or so the argument went.

• The rule is designed to increase competition in the transmission industry. By eliminating a federal right of first refusal for incumbent transmission providers to construct proposed transmission projects and requiring regions to have a formal planning (and often a competitive bidding) process for transmission projects, competition in transmission development would rule and consumers could benefit commensurately.

• The rule is designed to help overcome the inherent tension between generation and transmission. This argument was particularly salient in restructured regions of the country where an incumbent merchant generator might have self-interested reasons to maintain the price separation available to a generator in an area with transmission congestion.

In sum, if the following questions were asked of FERC:

"Is the main purpose of Order No. 1000 to get more transmission investment or is it to increase competition in the transmission business? OR, is Order No. 1000 designed to overcome the potential self-interest of generators or is it to promote renewable generators? OR, is it designed to support individual state public policies or is it a federal initiative to increase regional planning conducted by the RTOs rather than by the individual state regulated utilities themselves?"

The answer would seem to be an unequivocal "YES!"

Therein lay some of the unresolved tensions within Order No. 1000 which differentiates it from prior FERC orders like 888 and 636. While, like Order No. 1000, Order Nos. 888 and 636 entailed hard regulatory choices, stakeholder arguments and numerous complicated proceedings to implement them, FERC itself seemed to be pulling industry toward a fairly clear goal of what was to be accomplished under each of these seminal Orders.

Such clarity and single-minded purpose escapes the grasp of Order No. 1000. The Rule is held in the eye of the beholder. If you like supporting state or federal public policy requirements...
(whatever they are or whatever divergent goals they might hold), competition, renewables, greater planning, articulated cost allocation principles, decreasing the power of incumbent generators; then you are in luck, because Order No. 1000 has a process for you!

V. Implementing Changes Nationally without Fully Appreciating Regional Differences

Not only does Order No 1000's lack of focus create internal tensions within the rule itself, but these tensions are then superimposed on an electric industry that is highly regional in polity and practice; and these are factors that Order No. 1000 has little ability to accommodate; though through its implementation, it does its best to avoid acknowledging this reality.3

A. Order No. 1000 in Regions with Vertically Integrated States in Traditional Bilateral Markets

One of my own "lightbulb" moments as it related to this issue was in contemplating how little sense the full Order No. 1000 compliance regime made in a state like Florida. I hope readers will pardon me if I quote from my own separate statement attached to the 2013 Florida compliance order:

"... this filing raises in my mind certain broader concerns regarding the general direction Order No. 1000 takes us in relation to non-market, non-RTO/ISO regions. As I have previously written, there is much I can find worth supporting in Order No. 1000 and some of the subsequent compliance filings. Facilitating cost-effective transmission solutions, encouraging regional planning to meet customer needs and ensuring fair cost allocation are worthy endeavors. Greater standardization of those efforts would seem to hold a good deal of potential, especially in those regions of the country that have already voluntarily organized themselves into functioning RTOs and ISOs. But Order No. 1000 may not fit quite as well in certain regions of the country. Florida is a prime example.

Order No. 1000 seeks to ensure that transmission projects are planned in a cost-effective manner and in such a way that public policy goals are met. In highly integrated regions, where there is

---

3 In the spirit of full disclosure, this has long been a topic about which I have expressed a degree of concern. While I was not a member of FERC when Orders Nos. 1000 and 1000-A were adopted (and was recused from Order No. 1000-B), I did have the opportunity to review and vote on the many regional compliance orders that were filed during my term on the Commission (2012-2016). While individual regions had some degree of flexibility to tailor their compliance filings, that flexibility often seemed to me a bit illusory.
central dispatching, locational marginal pricing, and numerous state public policies that support geographically remote sources of generation, Order No. 1000 seems a reasonable effort to ensure just outcomes.

But in a region like Florida, I cannot help but ask if the bureaucracy imposed by Order No. 1000 may outweigh the benefits to be gained.

The FERC jurisdical utilities that serve Florida are vertically-integrated, monopoly utilities whose planning and operations are comprehensively regulated by the State of Florida. Integrated resource planning and facility siting, as approved by the state, ensures that generation and transmission decisions are viewed and approved holistically. The Florida utilities' integration with the rest of the greater southeast region is limited physically due to Florida's unique geography. There is no central dispatching entity and no LMPs to reflect local congestion. Florida utilities have exercised their right to retain control of their transmission by not choosing to join an RTO/ISO. The Florida Parties state that there are no identified public policy requirements driving regional transmission needs. Thus, in large part, the rationale for Order No. 1000 is lacking in Florida.

Therefore, I am not entirely sure what is accomplished by Order No. 1000 in such a region. On one hand, since a good deal of integrated resource planning is already happening, there is a chance the real net effect of these changes will fall somewhere between minimally and modestly beneficial. But I fear by shoehorning Order No. 1000 into a region with existing and extensive state-led planning, we could risk the creation of an expensive, potentially litigious, and time-consuming additional layer of unnecessary bureaucracy. If this happens, the counter-productive result will not be more cost-effective and timely built transmission, but less.4

At the risk of appearing self-congratulatory, these concerns from 2013 have been largely realized in the non-RTO, bilateral market regions of the country.5 Though I am unaware of a comprehensive study of the total costs of Order No. 1000 implementation, if anecdotal discussions with industry participants are any guide, initial and ongoing compliance expenses are greater than immaterial.

As to the benefits, one would be hard pressed to point to concrete Order No. 1000 successes in bilateral market regions of the country.

---


5 For purposes of the white paper I use the terms like bilateral market regions, and non-RTO, non-organized market regions to differentiate them from those regions of the country that operate within FERC jurisdical, organized, centrally-dispatched energy markets such as those served by SPP, CAISO, MISO, PJM, ISO-New England and the New York-ISO.
to point to concrete Order No. 1000 successes in these bilateral market regions of the country. No doubt some good has come from the mandate that regions do a more systematic job of planning and determining cost allocation principles, but one would struggle to pinpoint major accomplishments that were not already being achieved through the traditional state-led regulatory processes that oversee the vertically integrated utilities that exist in these bilateral market regions of the country.

To once again juxtapose Order Nos. 888 and 636, one of the reasons those rules have had greater impact and staying power was that FERC focused its reforms on areas in which its regulatory jurisdiction was more comprehensive—the terms and conditions of interstate electric transmission and natural gas transportation service. In contrast, Order No. 1000 occupies that blurry space at the intersection of state and federal policy. While FERC has undisputed authority over wholesale electric rates and over rate setting and cost allocation for interstate transmission service, Order No. 1000 closely intersects with areas that are just as clearly within state jurisdiction: integrated resource planning, resource adequacy, transmission certification and siting, not to mention state public policy goals that promote various forms of energy generation. Given all that, it is little wonder the impact of Order No. 1000 on actual transmission planning and construction has proved most ineffectual in those regions of the country where states have maintained the greatest degree of regulatory authority.

B. Order No. 1000 in Regions with Vertically Integrated Utilities in Organized Markets

The foregoing discussion is not to suggest that Order No. 1000 has conversely been a rousing success in the organized market regions of the country, only that the Rule’s ineffectiveness has been most pronounced exactly where you would expect: where state authority is still most comprehensive.

In my statement on the 2013 Florida compliance filing, I directed my suspicions about the efficacy of the Order No. 1000 planning regime, in part, towards those regions of the country that did not have an organized dispatch market, mentioning as a distinguishing characteristic, "There is no central dispatching entity and no LMPs to reflect local congestion. Florida utilities have exercised their right to retain control of their transmission by not choosing to join an RTO/ISO."6

This point is critical in understanding one of those underpinnings of FERC's Order No. 1000 rationale: the tension between generator self-interest and the impact of transmission planning. And while the point is valid, in retrospect, I think I drew the distinction in the wrong place. Specifically, Order No. 1000’s mismatch is most glaring not just in regions outside of organized markets, but rather, anywhere states continue to exercise their oversight of the traditional vertically integrated utility business model, whether in an organized market or outside of one.

Over the years, I have come to appreciate that the primary distinguishing characteristic between different electric utility regulatory ecosystems is how each state chooses to structure it. In this light, I postulate that an Xcel Energy in MISO and a Dominion Energy in PJM share more in common with a Florida Power & Light in Florida, than any of them share with a fully unbundled Exelon operating in a restructured state like Pennsylvania.

This only makes sense. Much like the example of Florida utilities planning distribution, generation and transmission holistically for a region (with the oversight of the state), vertically integrated utilities within an organized market undergo a similar planning process. It's just that in the day-ahead and real-time energy markets their units are centrally dispatched by an independent market operator. This is far different than in restructured states, where only distribution operates as a monopoly, and transmission and generation operate independently of each other, with wholesale administrative market mechanisms established by FERC to help inform the business decision making process of merchant operators.

With this understanding, it should come as little surprise that the unimpressive effects of Order No. 1000 on the organized markets in the vertically integrated regions of the country mirror the effects on regions outside of the organized markets.

SPP and MISO offer two real-world examples of the pitfalls of Order No. 1000 in practice.

Dating back to my time as a member of the North Dakota Public Service Commission, I had a pretty good sense of what I thought Order No. 1000 was trying to accomplish. It looked and sounded an awful lot like what we had already been doing, but with an overlay of additional FERC compliance burdens.

From 2008-2010, I was a member of an initiative started by the Governors of the States of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin, known as the Upper Midwest Transmission Development Initiative (UMTDI). Like nearly all other states in MISO, these are all vertically integrated states. While each state had its own reason for joining, the collaboration helped vet a series of transmission projects that seemed to establish a baseline of “no regrets” lines that met the needs of each state.

The work of UMTDI dovetailed with other regional efforts like the “Cost Allocation and Regional Planning” process and the utility-driven CapX2020 initiative, which provided various levels of support for plans that all eventually funneled into a suite of broadly acceptable transmission projects that became known as “Multi-Value Projects” (MVPs). The MVPs were approved by MISO and integrated with its transmission planning process, and ultimately upheld by both FERC and the courts. As the name suggests, these projects served multiple needs. They displayed shared characteristics of reliability lines, market efficiency lines and lines that supported various state public policies.
These efforts were bottom-up, inclusive, cognizant of state public policy initiatives, and successful in getting a lot of needed transmission built. It was also done before FERC Order No. 1000.

In a similar way, the SPP region (another region made up of vertically integrated utilities) had successfully ushered in a series of reforms through its highway-byway model prior to Order No. 1000.

Yet since the rule has been promulgated, much of this type of transmission activity has slowed to a crawl in the very regions where it had previously been most robust. While some of this may be attributed to flattening electricity load growth, and the fact that these projects alleviated some of the pent-up need for additional transmission projects, I would suggest that an ossified and bureaucratic Order No. 1000 planning process actually stifles what was previously happening organically. Insofar as this is true, it would indicate Order No. 1000 has not just been ineffective in certain regions of the country, it is actually counterproductive.

It is in regions where vertically integrated (and state-regulated) utilities participate in organized markets that we can see most clearly the effects of Order No. 1000’s series of unresolved and sometimes contradictory goals. If the rule’s goal was to incorporate state public policy planning and establish cost allocation certainty in order to build transmission, then these regions were already doing that.

Yet these regions were admittedly not at the forefront of prioritizing the injection of non-incumbent transmission competition into the planning process because, frankly, the concept has limited value and appeal in a region where the states themselves have determined that they prefer the regulated, vertically integrated utility ecosystem. In addition, FERC’s insistence that even one penny of regional cost allocation ended an incumbent transmission owner’s federal right of first refusal caused a series of cost allocation methodologies that previously had garnered widespread acceptance to fall apart.

In short, at least within MISO and SPP, the two RTOs that are most representative of joint dispatch markets composed of vertically integrated utilities, Order No. 1000’s pro-non-incumbent “competition” goals ran headlong into its state public policy and pro-transmission investment goals. We have been left in, arguably, a worse position than where we began: more process, more compliance, more delay, more paperwork, more planning; less transmission actually being built.

Indeed, a number of states continue to assert a state right of first refusal, further emphasizing this point.


Beyond the scope of this paper is a comprehensive analysis of how Order No. 1000 is unfolding in each distinct region of the country. Sagas like the PJM Artificial Island project will prove instructive as to the promises and
VI. The Times They Are A Changin’

In a turbulent era, Bob Dylan reminded the world that “The Times They Are a Changin’.”¹⁰ So, too, have there been a lot of changes in the electric industry since the Order No. 1000 rulemaking process started in 2010.

Order No. 1000 has its roots in the transmission planning principles FERC established in 2007 in Order No. 890 and was influenced by the Energy Policy Act of 2005’s (EPAct 2005) emphasis on reinforcing the transmission system and encouraging the construction of new transmission facilities. In 2007, gas prices were high and growth in electric energy usage seemed limitless. Transforming the transmission system, or at least building it out, would be necessary to bring renewable energy resources online that could satisfy the country’s appetite for electricity and wean the nation off of natural gas. As I describe above, regional transmission planning was already underway before FERC promulgated Order No. 1000. Numerous multi-region high voltage transmission projects—the type that seemed to be the goal of rule—were being developed by the time FERC issued its proposed rule in 2010.

Now that the rule has been promulgated and the planning processes have been formalized, where are the projects?

A lot has changed since the Order No. 1000 rulemaking process was begun in June 2010 — flattened demand, increased reliance on cheap natural gas, increased energy efficiency, and the growth of demand response and distributed generation. The combined effect of these and other changes may have made multi-state superhighway transmission projects less viable (and less necessary in order to satisfy state or national policy goals). Order No. 1000 was designed to address problems that existed when Order No. 890 was being implemented, and to facilitate the goals of EPAct 2005. The Order remains, but the problems it was designed to address, to the extent they were truly problems, have largely gone away or transformed themselves.

VII. Where Are We and Where Do We Go from Here?

If it is true, as psychologist Nathaniel Branden said, that “the first step towards change is awareness,” then Order No. 1000 may be ripe for a reassessment.¹¹ There seems to be a growing number of individuals aware that the rule has missed its target, or targets, as it were.

¹¹ In 2016, ScottMadden published a whitepaper that examined the effectiveness of Order No. 1000, stating “it is useful to assess whether the industry has achieved competitive processes as originally intended. While opinions vary
Unfortunately, there is less agreement about what to do about it. The camps basically break into three, and view the current status of Order No. 1000 as either:

A. A fundamentally sound idea that is making painfully slow progress towards some goals, but not others, such as large interregional transmission projects; or
B. Something that may not ultimately accomplish a lot, but it seems to encourage some laudable things; or
C. Proof of the law of unintended consequences, a rule, as currently constructed, that is generating more costs than benefits.

What you think should be done to change the rule is ultimately dependent on which camp you fall into.

For those who see the rule as generally described in proposition “A” there will be a temptation to double-down on Order No. 1000’s most prescriptive aspects. If new projects aren’t being built, it must be because incumbents and states have dug-in their collective heels, goes the theory. They are gaming whatever flexibility was provided in the original compliance filings so it is time to tighten the screws. Less flexibility is the answer and let us drive Order No. 1000 deeper and deeper into the grid. Let’s drive it down to lower voltages. Let’s make sure those projects don’t escape our planning processes by popping up as thinly veiled “reliability projects.”

Let us call this approach, “the beatings will continue until morale approves!” solution.

I strongly urge that we avoid this path.

If the goal is to make sure that even less gets built than under “Classic Order No. 1000,” then this is would be the way to accomplish it. Order No. 1000’s requirements have changed the goals of transmission planning. Before the rule, the purpose of the planning processes was to identify necessary improvements in electric energy infrastructure. The imposition of Order No. 1000 has created a new litmus test for success: identifying projects that can satisfy the rule, particularly a project that is eligible for interregional cost-sharing.12

As I describe earlier, Order No. 1000’s requirements are oftentimes redundant to pre-existing state regulatory schemes for vertically-integrated utilities, simply adding an unnecessary layer of regulatory process. Expecting regions and RTOs, which are already struggling under the weight of their existing regional and interregional planning processes, to impose said process even further down to the next level on the grid invites even more stagnation and death by bureaucracy. All of the unresolved internal conflicts with the divergent goals of Order No. 1000 that I have written about by stakeholder and region, we believe the answer to this question is a resounding “no.” Cristin Lyons and Brian Messick, FERC Order No. 1000: Five Years On, June 2016, at 3, available at http://www.scottmadden.com/wp-content/uploads/2016/06/ScottMadden_FERC_Order_1000_2016_0601.pdf.

12 As an aside, it’s interesting that a transmission project located entirely in Missouri might cross through multiple regions, and, therefore, be a success under Order No. 1000 interregional planning; but a transmission project that would run the length of the Mississippi River could be located entirely in the MISO region, and, therefore, worthy of no particular merit under the rule.
become more problematic at this level. This change wouldn't alleviate Order No. 1000's problems, it would exacerbate them.

Those who fall into camp "B," "Order 1000 may not ultimately accomplish a lot, but it seems to encourage some laudable things" are the most status quo oriented of the bunch. They are probably aware that the rule is not working as intended, but are cautious by nature, and think that any problems should be addressed incrementally. Their argument might be: At the very least, letting the rules collect a bit more dust wouldn't seem to do much harm while we give Order No. 1000 more time to mature. People who fall into this camp may also be of the opinion that Order No. 1000 is actually doing more harm than good, but they are concerned that once FERC begins tinkering with it, they might end up with something worse: better the devil you know than the devil you don't.

Finally, are the people who are in camp "C," those who have come to the conclusion that no matter how well-intentioned the rule, the cumulative weight of it can no longer be justified by its results, or lack thereof. Count me among their number.

Even within Camp C, no doubt, there is a variety of opinion on what to do about the failed Order. "Be done with it already" is certainly one path, and given the paucity of hard data that supports Order No. 1000's efficacy, and the difficulty in evaluating what data exists, it would be an understandable response. However, realists about government action have to acknowledge that history is not replete with examples of government regulatory agencies on their own "calling a mulligan" and dismantling a regulation of Order No. 1000's scope.

VIII. The Order No. 1000 Reboot

My suggestion is for FERC to step back and reassess Order No. 1000's key goals and adjust accordingly.

The "supporting public policy requirements" goal, while a nice sounding bumper sticker, fails in practice. State policies, to the degree they happen in vertically integrated states, are already self-supporting through state-led resource adequacy and integrated resource planning that has gone on for years. In restructured states, goals and requirements have been shifting rapidly in recent months, as state governments in such places as diverse as Illinois, New York, New Jersey, Massachusetts and Connecticut devise around market actions to prop-up ailing and politically favored generators. At the Federal level, to the degree the nation has public policy requirements that would establish a national energy policy, they are vague, at best. As previously noted, there is no stated national energy policy. To the degree there is an implicit energy policy guided by

13 See, e.g., Federal Energy Regulatory Commission, 2017 Transmission Metrics: Staff Report, Oct. 6, 2017 at _, available at https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf. The Staff Report notes that "it is difficult to assess whether the electric industry is investing in sufficient transmission infrastructure to meet the nation's needs and whether investments made are more efficient or cost effective." Id. at 6.
Presidential ambitions, in the last 18 months it has shifted from an administration for whom GHG policy was the overriding factor to one that emphasize energy dominance, security and economic development. Given the nature of these competing state and federal energy visions, it would be better for FERC to step away from this aspect of Order No. 1000. At most, a FERC requirement that that utilities located in the same and adjacent regions compare notes and plan for efficiencies should be more than enough to deal with this matter.

Eliminating the public policy requirements goal also has the benefit of discarding one of the thornier problems embedded in Order No. 1000. When state goals come into conflict (e.g., state A has a particular flavor of an RPS, state B does not, and would like to support its own native generation, thank you very much), who decides which state's requirements are valid? The planning region? The RTO? FERC?

Even in regions that might support some of the competition goals of Order No. 1000, the public policy requirements goals sound better on paper than in practice. Take for example, recent efforts in New England to build transmission from Canada for access to Canadian hydro. The region is predominantly restructured. Massachusetts has a state public policy to use more hydro power. But New Hampshire does not, and has shown no intention of allowing a transmission line to be sited through it for the benefit of Massachusetts energy priorities. FERC rules or not, there is nothing in the Federal Power Act that resolves that situation. And multistate RTOs are not in a position to pick which state's policy should take precedence over that of another state.

So if we take out the canard of supporting state and federal public policy requirements, what are we left with? I would suggest that a potential nugget within FERC Order No. 1000 that bears ongoing consideration is related to the notion that in certain restructured regions of the country, there is a potential disconnect between transmission planning decisions and generation/market decisions. Issues related to the changing generation portfolio, the desire for fuel diversity, and effects of low gas prices and the growth of renewables are related to the challenges of transmission congestion reduction. The way to address these related concerns is to require transparent regional transmission planning, interjected with the ability of non-incumbents to compete for those projects.

But here is the rub; that problem statement should not be addressed through nationwide fiat, but rather as a rule primarily targeted towards "Restructured Administrative Markets."

---


If FERC more clearly targets Order No. 1000 to address this issue, then it need not impose the requirements on those regions where they make little sense. If that sounds somewhat familiar, it should, because it is essentially the policy call FERC made when it only approved capacity markets for regions of the country that had substantially restructured. For all of the problems and controversies that exist with capacity markets, at least it can be said that FERC has tacitly acknowledged that they only seem to have a role where the structural characteristics of the market fit.

If only FERC would make such an acknowledgment in the Order No. 1000 planning space, much of the Order No. 1000 conundrum could be avoided. It could accomplish this by targeting the bulk of the Rule to the Eastern Capacity Market regions of the country, while substantially repealing or reducing it in those areas where it is less justified, and which were inarguably meeting much of the spirit of Order No. 1000 prior to its imposition.

IX. Conclusion

FERC Order No. 1000, for all its good intentions, is today a rule that has largely fallen short of accomplishing its goals. Unfortunately, the failure of it to fulfill its potential has not come without costs. Given the changes in the electricity industry over the last decade, now is a good time for the Commission to consider an Order No. 1000 reassessment. FERC would do well to ask, “What are we really trying to accomplish?” and then tailor the rule narrowly to achieve those goals. Clinging to an increasingly odd fitting rule in the face of growing evidence that it is not working will only increase the difficulty of reforming it when that time eventually comes.
STATEMENT OF EDWARD KRAPELS

Mr. KRAPELS. Thank you, Mr. Chairman and distinguished members of the Energy Subcommittee.

My name is Ed Krapels, and I am the founder and CEO of Anbaric, which is an independent transmission microgrid storage and smart energy campus developer. We are funded by institutional investors, so we are not your typical utility.

We like to think we build the electric businesses of the future, and the future is very different from the past, as other members have already indicated. We helped to spearhead two high-voltage direct current buried transmission lines between New Jersey and New York. The high-voltage direct current technology is common worldwide, but not widely used yet in the United States.

As a person who has actually developed interregional transmission projects, I have taken the opportunity to write an article that is part of my prepared testimony that was just published in The Electricity Journal called “Triple Jeopardy.” It reviews why, even though everyone agrees these kinds of interregional transmission links are useful and that more are needed, both existing and new interregional projects are being choked off by well-intentioned but unproductive regulations.

Some of these stem from Order 1000 and the inability to implement Order 1000 in a way that is sufficiently prescriptive to handle the many issues that arise when interregional transmission projects are proposed.

I am here this morning, however, to discuss a really important new opportunity in our power industry. Federal energy and environmental policy can accelerate what promises to be a once-in-a-generation chance to launch a new domestic industry, and that is offshore wind, if we do it smartly and thoughtfully from the start.

The key to success is to plan, design, and build shared independent offshore transmission, OceanGrids, in a thoughtful way in each of the participating coastal States. The Federal Government obviously has a huge role in this through the BOEM and FERC procedures that have to be implemented as part of this plan.

Why are these planned and independent OceanGrids so important? Because after years of development in Europe, technology has pushed the price of offshore wind down to super-competitive levels. With that, American offshore wind is now a natural component in the administration’s energy dominance strategy. It is indeed fuel from heaven, and its time has come. However, as with all large-scale energy resources, indeed with any important new industry, the business, financial, and physical platform on which it is built must be carefully designed and developed.

Unfortunately, some ideas about offshore wind would jeopardize the ability to realize its full potential. Early policy proposals in Massachusetts, New York, and New Jersey explicitly would give generators the exclusive ability to own the transmission lines that
take offshore wind to market. These proposals have been promoted by giant, largely European wind developers that would get America’s offshore undertaking off on an anti-competitive and wrong footing. It is obviously in their interest to control as much of the access to the onshore grid as possible. If we allow that to happen, we will lose the kind of competition that will further lower offshore wind prices. We will lose more fishing grounds because there are more subsea cables than necessary. We will lose control over a substantial portion of our own coast. A proliferation of cables would displace and distress marine life during construction and operations and make it hard to avoid estuaries and navigate sensitive shoreline points of entry that will undermine an industry in a vital period of its growth.

We are proposing in our OceanGrids a smaller number of large collector stations that are placed at the edges of the offshore wind farms, gathering the electricity from multiple wind farms and bringing it to shore via the minimum number of transmission cables buried in the seabed. These cables would be buried under the ocean floor and sized for multiple wind projects, and it could be either direct current or alternating current, depending on the distance to shore.

If we do it right, we will create an industry and tens of thousands of 21st century jobs. We will create competition between generators. And it is that competition that will bring the price of offshore wind down to market levels.

I will close by saying that in Europe today offshore wind auctions are yielding prices of 4 to 5 cents per kilowatt hour, which is pretty close to the market price.

Thank you very much.

[The prepared statement of Mr. Krapels follows:]
Mr. Chairman, distinguished members of the Energy Subcommittee of the House Energy and Commerce Committee. Thank you for inviting me to testify on the State of Electric Transmission: Investment, Planning, Development and Alternatives.

My name is Ed Krapels and I am the founder and CEO of Anbaric. We build the electric businesses of the future. We helped spearhead two high-voltage, direct current buried transmission lines between New Jersey and New York, increasing market efficiency and saving ratepayers hundreds of millions of dollars as a result. This high-voltage direct current technology is common world-wide but not used much in the US — its small size makes it well suited to linking markets in congested areas of the country where construction is difficult. An article I have just published in The Electricity Journal, reviews why — even though everyone agrees these kinds of interregional transmission links are useful and more are needed — both existing and new interregional projects are choked off by well-intentioned but unproductive regulations. That article is part of my written testimony.

We come here this morning, however, to discuss an extremely important new opportunity in our power industry. Federal energy and environmental policy can accelerate what promises to be a once-in-a-generation chance to launch a new domestic industry — offshore wind — if we do it smartly and thoughtfully from the start. The key to success is to plan, design and build shared, independent offshore transmission systems — OceanGrids — in each of the participating coastal states.

Why are these planned and independent OceanGrids so important? Because, after years of development in Europe, technology has pushed the price of offshore wind down to super-competitive levels. With that, American offshore wind is now a natural component in the Administration’s Energy Dominance strategy. It is indeed Fuel from Heaven, and its time has come.

However, as with all large-scale energy resources — indeed, with any important new industry, the business, financial, and physical platform on which it is built must be carefully designed and developed. Unfortunately, some ideas about
offshore wind would jeopardize the ability to realize its full potential. Early policy proposals in Massachusetts, New York and New Jersey explicitly would give generators the exclusive ability to own the transmission lines that take offshore wind to market. These proposals have mostly been promoted by giant, largely European wind developers that would get America’s offshore undertaking off on an anti-competitive, wrong footing. It’s obviously in their interest to control as much of the access to the onshore grid as possible.

If we allow that to happen, we will lose the kind of competition that will further lower offshore wind prices. We will lose more fishing grounds because there are more subsea cables than necessary. We will lose control over a substantial portion of our own coast. A proliferation of cables would displace and distress marine life during construction and operations, and make it hard to avoid estuaries and navigate sensitive shoreline points of entry. It will undermine an industry in a vital period of its growth.

What we are proposing in our OceanGrid is a smaller number of large collector stations that are placed at the edges of the offshore wind farms, gathering the electricity from multiple wind farms and bringing it to shore via the minimum number of transmission cables buried in the seabed. These cables would be buried under the ocean floor and sized for multiple wind projects and it could be either the size I showed you earlier or this size.

If we do it right, we will create an industry and tens of thousands of twenty-first century jobs. We will create competition between generators. We will create low power prices. And we will preserve the coast. Because we will create an industry here in America, we will increase and enhance our energy independence. The results: “zero-subsidy bids” from wind generators in the European countries which have followed the separate OceanGrid strategy.

The slides at the end of my prepared testimony illustrate what’s needed. It shows the New Jersey and New York coastlines, where almost 8,000MW of wind — enough to power 4 million homes — will be built offshore in the coming decade. The first map shows where the designated wind areas are in relation to the coastlines of New Jersey and New York. The wind areas are in federal waters, and the power must be brought to shore in an efficient and environmentally sound manner.
The second map shows the effects of each 400MW wind farm building its own transmission lines to the coast. The third and fourth maps show the other cables, shipping lanes, ocean disposal sites, artificial reefs, unexplored ordinance, and other danger zones and restricted areas that impede the transmission cables paths to shore.

Anbaric’s OceanGrid proposal is shown in the last slide. Instead of 20 small cables, we envision 5 to 10 cables designed to carry the maximum amount of electricity per conduit. The plan can be executed in phases, and the technology can be adapted to the needs of the specific procurements that each state will conduct.

America has a once-in-a-lifetime opportunity to create a new industry. Let’s maximize the prospects of success from the start – with a thoughtful and far-sighted approach to planned transmission that benefits taxpayers, electricity consumers, businesses, and our nation’s economy.

Ladies and Gentlemen of the Committee, as we welcome this important new offshore wind energy industry, let’s dedicate ourselves to ensuring that the states, industry leaders, utilities and regulators, with appropriate Federal oversight, embrace the urgent need to build this critical new infrastructure in the right way from the start.
Anbaric's Proposed OceanGrids of New Jersey and New York
Attachment to Prepared Testimony of Edward N Krapels, CEO of Anbaric, before the Committee on Energy and Commerce, U.S. House of Representatives
May 10, 2018
SUPPLEMENT TO TESTIMONY OF EDWARD N. KRAPELS, CEO OF ANBARIC DEVELOPMENT PARTNERS, BEFORE THE ENERGY SUBCOMMITTEE OF THE HOUSE ENERGY AND COMMERCE COMMITTEE, MAY 10, 2018

“Triple Jeopardy: How ISOs, RTOs, and incumbent utilities are killing interregional Transmission”

By Edward N. Krapels

To be published in The Electricity Journal
May 2018
Triple jeopardy: How ISOs, RTOs, and incumbent utilities are killing interregional transmission

Edward N. Krapels
Anbaric Development Partners, 491 Highwood Pl, Suite 600, Wakefield, MA, 01880, USA

ABSTRACT

Everyone agrees interregional transmission is useful and firmly needed. Yet both new and existing interregional projects are treated unrealistically. Why?

1. Summary

Over the last two decades, innovative electric interregional transmission ideas have emerged all over the country in response to the opening of transmission to competition by federal and state regulators, but very few have been built. In the West, several multibillion-dollar power lines are under development that would connect the remote rural areas of Wyoming, Nevada, and New Mexico to California. In the Northeast, new transmission proposals are competing to build the links with Quebec and the Maritimes. In the mid-continent, bold transmission initiatives would connect previously unconnected states and provinces. In each of these areas, interregional electric trade is viewed as a beneficial result of new infrastructure. After all, transmission is the power system what the interstate highway system is to the broader economy: it is the infrastructure that facilitates trade to the benefit of both sides of the line. Those who can make electricity more cheaply can export it to those where it is more costly. Both sides benefit.

This is why the nation’s chief electricity regulator, the Federal Energy Regulatory Commission, or FERC, issued “Order 1000” in 2011, to accelerate the development of interregional transmission lines. Seven years later, however, little has been done because FERC has not sufficiently persuasive in how interregional projects should be treated by those who have the power to approve and maintain them at a regional and state level. In the pages that follow, the expected costs and benefits of some proposed and some built interregional projects between New York and its neighboring power markets will be reviewed to support the argument that FERC needs to do more to get the desired results from Order 1000.

The new FERC commissioners appointed by President Donald Trump have a number of opportunities to free the development of innovative interregional transmission proposals from a “triple jeopardy” that not only discourages anyone from proposing new projects, but renders existing projects unviable. The development of new interregional transmission lines should be an important federal policy goal for the Trump Administration because it will promote economic growth within the United States. To get that growth, FERC needs to develop a more prescriptive policy on how such projects can be originated and how their cost should be allocated.

The interregional “planning” that was promoted by the Obama-era FERC almost always reaches a dead end because these organizations have been dedicated to maintaining the reliability of their systems without depending on neighboring regions. That’s why the primary reason to build interregional transmission lines should be similar to the primary reason to build the interstate highway system: an infrastructure that unites the states and enables economic growth.

2. The first jeopardy: interconnection costs

In the process of development of any electric asset, the sponsor must make an interconnection filing to the transmission entity to which the project intends to connect. In organized power markets, this is an
The second jeopardy: revenge of the urban generator

No technical shift can occur in the electric topography of any market without a challenge from those who have invested in the status quo. If most ERCs and ISOs, capacity market rules were developed or evolved to prevent new transmission lines from allowing electric capacity expansion, we would see a similar pattern in the U.S. Proposition of these oppositeness issues concern a novel market structure that should not be allowed to limit capacity expansion. The argument which, applied to other American businesses, would prevent any more roads from being built lest they harms the businesses of the incumbents.

For example, in the PJM market, such challenges occurred in the form of changes in the NYISO’s capacity regulations and the form of cost allocation “surprises” in the PJM market. To explain what happened in New York requires a quick review of how the NYISO works. Under FERC rules, the NYISO can propose amendments and modifications to the existing transmission use rates and FERC approves and disapproves them. For a period of several years ending on September 27, 2010, the NYISO sided over the outcomes of a series of rules that would ultimately be called “market power mitigation measures applicable to the New York City (In-City) Installed Capacity (ICAP) market.” In effect, if not in intent, was to protect New York City generators from enhancements to the transmission system.

The original regulations for the New York ISO’s ICAP market created a periodic auction of the existing and proposed capacity, with minimum and maximum bids set in New York for peak and critical time periods in New York City, Long Island, and “nearby” [3]. The intent was to protect buyers against market power and predatory pricing by generators (hence the need for a ceil price for capacity services). The intent was to protect generators against monopoly power in the form of efforts by utilities and Authorities to subsidize new generation and thus drive the price down (hence the need for a floor price for capacity services). To qualify as capacity reserves and earn capacity reserves, new projects had to qualify as “competitive entities.” The language selected for this assignment was "NET CONE", as an acronym for Cost of New Entry.

As usually happens in these types of regulatory constructs, the devil is in the details. The key parameters are the definition of what constitutes a competitive entity and how the price floor and ceiling are calculated. These constructs were embedded into what is called a “demand curve” for capacity that allows the capacity price to go up and down between the floor and ceiling. In response to the changes in the balance between supply and demand, the price floor and ceiling were determined to be in response to the cost of a theoretical new generator unit, yet CONE. The floor was set to protect generators against subordinated competition at 75 percent of "NET CONE." With these mechanisms, the NYISO subjected projects to a Mitigated Exemption Test (MET). If a project was exempt, it could participate in the capacity market without requirements. If it wasn’t exempt, if it was deemed "outcompete," it would be prohibited from participating in the capacity market for a defined period of years. Such a prohibition would cost the project tens of millions of dollars per year in revenue.

However, one’s opinion of this comment for generation, the NYISO first applied this constraint to a transmission line (NTS) in 2012 when it linked the capacity reserves that might be provided in NTS across HTP and an MOP "under constraint" and therefore would be subject to the MET. HTP subsequently lodged a complaint with FERC arguing against this ruling, but HTP based its arguments on relatively narrow grounds pertaining to timing and the other figures to be in the MOE. HTP’s Complaint didn’t raise the larger issue of how ICAP would be applied to new transmission lines at all. The more fundamental question — absent asked by the transmission owners — is whether it is appropriate — even in pricethe — to apply the MET to new transmission lines.

---

1 For example, the author’s 2005odel of the projects for the New York Independent System Operator Project, which the initial “feasibility” study concluded by FERC indicated the project would be up by 2010 million for in the NYISO system. On the basis of that study, FERC incorporated the next phase as a market design study. That study was delivered a year later and called for a new interconnection market program: 850 to 950 million. After another year of discussion between the HTPs and the NYISO, the final cost was netted at $750 million, after 1.25 years, which led to the ability of Hess transmission for rights transferred from the NYISO to the NTS.

2 The second ICAP Order was issued on November 30, 2010. See FERC Docket No. EL10-6-000.

3 The term "NET CONE" was used to mean New York City (In-City) Installed Capacity (ICAP) market.

4 This last ICAP Order was issued on November 30, 2010. See FERC Docket No. EL10-6-000.

5 The Energy Policy Act of 2005 (EPACT 2005) to means that the New York ISO (NYISO) is responsible for ensuring that the power system operates in a reliable and secure manner. The NYISO is the regional transmission organization (RTO) designated by the Federal Energy Regulatory Commission (FERC) to manage the bulk power system in the New York ISO service area, which includes New York State, New Jersey, and Connecticut.

6 The NYISO is responsible for ensuring that the power system operates in a reliable and secure manner. The NYISO is the regional transmission organization (RTO) designated by the Federal Energy Regulatory Commission (FERC) to manage the bulk power system in the New York ISO service area, which includes New York State, New Jersey, and Connecticut.
It seems plain that the NYISO committed a category error when it looked upon Hudson Transmission and assumed it was part of the category "generator," rather than in the category "transmittable communication infrastructure," which is a complex system for conveying energy, capacity, and ancillary services from one electric source to another. To compound the error, the NYISO treated the Hudson Transmission Project as a "generator lead line" that provides electric energy, capacity, and ancillary services from one specific generator to a specific point on the NYISO system. But the Hudson Transmission Project isn't a generator lead. It's a high-tech, controllable, system-to-system connection between the entire PJM system and the NYISO system. Ignoring the details of whether or not a particular generator is on or off. The road to the mall, it's in the category of infrastructure. A road connected to a mall doesn't change just because a street in the mall closes, it remains open.

Moreover, a generator is a market participant, a producer and supplier of electric energy and capacity, while a transmission line like Hudson Transmission earns revenue merely from providing transmission services, and its costs for doing so are based on the cost of constructing and operating the transmission assets. Hudson Transmission has no marginal costs of fuel. Unlike the cost and revenue streams for new generation and new transmission projects, which are fundamentally different. Given these different cost and revenue streams, the concept of "economic entry," as embodied in the NYISO's rules, can't be meaningfully applied to transmission lines. Equally important, the FERC applies different standards to evaluate and mitigate generation and transmission market power. The commission recognizes these fundamental differences by how it applies different standards for evaluating and mitigating generation and transmission market power, respectively. The commission assumes a generator market power passes through market share, pivotal supplier, or delivered price tests that are based on the amount of generation owned or controlled by a generator and its affiliation in a given market, and generators that fail those tests are mitigated by applying marginal cost-based offer caps or similar mitigations. The commission normally assumes that a regulated transmission provider with a franchised service territory (i.e., a non-merchant transmission line) has market power by virtue of the fact that transmission is assumed to be a "natural" monopoly. Consequently, the commission addresses this by requiring each transmission provider to provide service under an open access transmission tariff (OATT) or through transferring ownership (to an ISO-RTO) to an ISO-RTO that has direct service over the Hudson Transmission line is provided under the terms of an ABO/DO IOCT, and it's therefore inappropriate to impose additional mitigation on Hudson Transmission. Moreover, for merchant transmission providers such as HTP, the commission applies a four-prong test to evaluate requests for negotiated rate authority. To pass this test, the merchant transmission provider must demonstrate, among other things, that the line won't be located in the footprint of its own, or an affiliate's, franchised service territory, that it won't have the ability to exercise market power (instead it turns operational control over to an ISO-RTO), and that it can't engage in unlawful discrimination or affiliate abuse. 

The imposition of the mitigation principle on HTP robbed the New York Power Authority—which owns the transmission rights of one of HTP's primary assets: its ability to serve as a conduit to the PJM capacity market. Ironically, in most parts of America's vibrant and competitive market economy, it's considered a good thing for people to be able to buy from and sell to those they choose. HTP was about to discover, however, the electric market is not like the rest of the American economy. Years after the test was announced, HTP was afflicted by the third jeopardy.

4. The third jeopardy: revenge of the incumbent utilities

In 2015, the NYISO's category error was amplified and compounded by efforts of utilities on the PJM side of the transmission line to extract hundreds of millions of dollars of additional costs on HTP. The Project was designed to provide a way for its consumer - NYPA -- to purchase both energy and capacity from PJM. Each line is enabled by HTP because it is an integrated system for delivering electric energy to the PJM capacity market. For various reasons including, principally, the mitigation policy described in the previous paragraphs of this article, HTP's FTWVs were practically worthless.

In 2015, the New Jersey electric utility, PSEG, added insult to injury by trying to allocate charges for upgrades in the New Jersey electric system to New York consumers. Initially, the bulk of those upgrades were going to be assigned to a long-standing transmission agreement that is the basis for the PJM transmission line between New York City and New Jersey, but was never intended to benefit New Jersey consumers. The New Jersey PUC asked the FERC to look into increasing the mileage on transmission lines between New York and New Jersey. By contrast, if a generator in New York City is unable to meet the capacity market, it's not available to be used by NYISO to reduce the OATT or the RTO's base.
ment with Consolidated Edison (called "the Wheel"). Costly filed complaints against the allocation with PSEG, which the commission rejected, whereupon ConEd proposed the transmission rights that had been granted to it under the decade-old arrangement. The next project in line to be allocated this cost (about which more below) were the other New York-bound transmission lines, like HTP. The stakes in this RTO allocation drama were extremely high. Con Ed was assessed more than 80% of the $762.8 million for its 1,000MW wheel while PSEG with its load of 11,000MW was assessed only 7%.

This disproportionate allocation of hundreds of millions of dollars of RTO changes by EIB and PSEG to New York customers mixed huge quantities about the value and viability of interregional transmission. A NYPA filing to FERC noted that "As a result, the HTP FTRs—which were originally intended to impact a beneficial and valuable right to the holders—have not only become worthless, but now represent a $645 million liability that threatens the continued viability of the Hudson Transmission Project merchant transmission facility."[200]

For PJM's incumbent utilities, including PSEG, the presence of interregional projects like Neptune and Hudson presents an opportunity to impose the costs of system upgrades on "foreigners," in this case the customers of the New York Authorities who believed they could rely on reasonable role-playing in the "power market next door." Instead, NYPA observed in its July 2017 filing that PSEG "is clearly motivated by its fear that NYPA's current RTO cost responsibility...could ultimately be reassigned to PSEG." In a final irony, a few years earlier PSEG had been selected by the Governor of New York to manage the Long Island electric market. That assignment did not stop it from imposing hundreds of millions of dollars of additional costs on New York's electric customers.

5. Preventing unintended consequences

These interconnection procedures, MHT, and RTO regulations, while technical, have huge implications for interregional transmission projects. If they continue to be applied to transmission projects like the ones serving New York City and Long Island,[131] few new interregional projects will be built and some existing projects will become uneconomic. In many parts of America, transmission development is already incredibly difficult and demanding. The triple project suddenly looks almost impossible.

How to prevent the damage these injustices will inflict? It starts with FERC. FERC should finally follow through on its promise made in Order 1000 and create a new category of cost allocation for interregional transmission lines. The narrowest version of "beneficiary pays" is simply too restrictive, because it tends to rely too heavily on a static analysis of the effects of transmission, in conventional electric power system thinking, a powerflow model will show that a new transmission line will reduce the price in the "sending" market and lower it in the "receiving" market. But that static picture is never the entire picture. Instead, a transmission line changes the dynamic topology of the region in which it sits: it causes a new dynamic that in one year might be in the advantage of the source market, and another year in the load market. The courts have made this more difficult by imposing on extremely narrow "beneficiary pays" formulation. That had they applied to interstates highways, the interstate highways system would never have been built.

Second, FERC should direct all ISOs and RTOs to refrain from imposing mitigation rules on interregional transmission lines. Stakes here a right, and some would argue the federal government has a responsibility in encouraging interregional transmission and thereby enhance competition. The mitigation rules prevent that from happening by raising, not lowering, barriers to entry. For example, the NYISO should revise its Attachment H to eliminate the provisions applying the MHT to non-controllable transmission lines.

Third, FERC must not allow ISOs and RTOs to impose disproportionately large RTO costs on interregional transmission lines. Based on history, PJM's proposals imposing costs on "foreigners" is intolerable. While import customers should pay their share of maintaining value in the regions from which they import electricity, they should not be victims in the kind of extremely disproportionate allocations they have suffered in recent EIS, MHT, and RTO procedures.

The new FERC of the Donald Trump era has an opportunity to dismantle the triple property. With that, not only New York, Connecticut, and New Jersey but also parts of the country can get on with the development one of the critical components of the Administration's infrastructure policy, and make electric America great again.

Edward N. Krups is long has been active in the rising industry of nonutility electric transmission and distribution development. He is CEO of Atlantic Development Partners (ADP), a joint venture with Ontario Teachers Pension Plan whose transmission projects focus on bringing renewable energy into cities. A former financial advisor and risk management consultant, Mr. Krupa has published several books and hundreds of articles in energy industry journals. He was a member of Energy Secretary Steven's Chris Electric Advisory Committee from 2010 to 2012. The transmission sphere, Mr. Krupa has been a founding partner in developing several ground-breaking electric transmission projects, including the Neptune Regional Transmission System, the Hudson Project, and several major new projects designed to bring renewable power into urban markets (www.Atlantic.com). Mr. Krupa also has been active in the growing microgrid industry as a consultant. In 2009, of Vensys Energy, a company dedicated to optimizing demand-side management programs and developing the control software for microgrids. Atlantic has initiated a microgrid project development company with Enel (www.AtlanticMicrogrid.com) and is actively pursuing the development of the first generation of independent microgrids in New York State. The author holds a Ph.D. from the Johns Hopkins University, an M.A. from the University of Chicago, and a B.A. from the University of North Carolina, Chapel Hill. This article is based on a paper published with William Holdaway (a partner with the law firm Gibson Dunn & Curtis) in Public Utilities Fortnightly, and an earlier article written with Carla Bruce prepared for the Regional Plan Association in June 2013. The author was a principal with the companies that developed the Neptune and Hudson projects, which are discussed in this paper.
Mr. OLSON. Thank you, Mr. Krapels.

Our next witness is Jennifer Curran. Jennifer is the vice president, system planning, at Midcontinent ISO. But most importantly, she is a graduate of Rice University, my alma mater.

Ms. CURRAN. Go, Owls.

Mr. OLSON. Go, Owls.

Five minutes, ma’am.

STATEMENT OF JENNIFER CURRAN

Ms. CURRAN. Good morning, Vice Chairman Olson, Ranking Member Rush, and members of the subcommittee.

As noted, I am Jennifer Curran, Vice President of System Planning for the Midcontinent Independent System Operator, or MISO, as we are more commonly known.

I appreciate the opportunity to be here with you today as you examine the state of the Nation’s electric transmission system, and I hope the insight into how MISO plans transmission are useful to you as you work to shape U.S. energy policy.

MISO is a 501(C)(4) not-for-profit social welfare organization with responsibility for ensuring the reliability of the high-voltage electric transmission system to deliver low-cost power to customers. That mission is reflected in our approach to transmission planning. We seek not to minimize the cost of transmission, but rather to identify transmission, which maximizes value to customers in the form of overall lower total energy costs.

The system that MISO manages is geographically the largest in North America. It spans from Manitoba in Canada down through all or parts of 15 States to the Gulf of Mexico. As you might imagine, a geography that wide presents a lot of diversity in resource types, weather, State policies, and consumer preferences as it relates to electric supply. Transmission is a key tool to optimize that diversity for the benefits of customers. That diversity also presents challenges as we seek to design transmission plans and, probably most importantly, determine who will pay for them. Even prior to Order 1000, MISO was planning not just for reliability, but also for economics and public policy.

Of the $30 billion of transmission investment that has been enabled through the MISO planning process, approximately 20 percent of that is associated with a long-term regional planning effort to address the changing resource mix, known as the Multi-Value Projects.

The Multi-Value Project portfolio is a set of 17 projects that are distributed widely across the north and central regions of MISO. They provide benefits of two to three times the cost, predominantly in the form of access to existing and new low-cost energy resources, and reliably enable the renewable portfolio standards in the Midwest.

Transmission like the Multi-Value Projects is a longer-term view. We are about halfway through the implementation of the Multi-Value Projects, with the final project scheduled to go into service in 2023. In the meantime, as has been noted, we continue to see a great deal of change in the electric industry. So where do we go from here?
I think the challenge in front of us is probably best described by the two questions I get most frequently about transmission planning: MISO, why have you not developed the next set of regional and even interregional transmission? And, MISO, why are you thinking about additional transmission that we clearly won’t need?

So that dichotomy is clearly representative of the diversity that I mentioned, and that diversity becomes even broader as we expand beyond the regional boundaries and plan with our neighbors. But it is also reflective of the uncertainty of the future as it relates to electricity.

The MISO planning process uses a scenario-based approach. We try to bound the potential outcomes of the future and then look for transmission projects that will be valuable in all of those futures.

If we can find transmission that is valuable across that wide range of objectives, then we can feel comfortable that the benefits will continue to accrue to customers and that we can continue to recommend that transmission. We often refer to these as no-regrets projects.

We have a lot of planning to do to determine whether there is a future set of transmission that has benefits in excess of costs and, probably most critically, to come to consensus on who will pay for that transmission, who sees the benefits and believes that the cost they will bear will be in line with those benefits.

Nonetheless, I believe that regional and interregional transmission will be a critical part of the overall solution set as we seek to ensure the reliability, the efficiency, and the resilience of the electric grid into the future.

Thank you.

[The prepared statement of Ms. Curran follows:]
Testimony of Jennifer Curran
Vice President, System Planning
Midcontinent Independent System Operator, Inc. (MISO)

Before the House Committee on Energy and Commerce
Subcommittee on Energy

"Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction and Alternatives"

May 10, 2018
Executive Summary

- Midcontinent Independent System Operator, Inc. (MISO) Overview: MISO is a 501(c)(4) not-for-profit social welfare organization established to ensure the reliability of the high-voltage electric transmission system to deliver low-cost wholesale energy to consumers. MISO manages about 66,000 miles of high-voltage transmission lines and 175,000 megawatts of electricity-generating capacity and serves about 42 million people across all or parts of 15 states. This regional platform creates $3 billion in annual benefits for members and consumers.

- MISO's Transmission Planning and Development Process: MISO's grid planning and facilitation of infrastructure investment has been a key contributor to the region's ability to efficiently and reliably manage the ongoing generation portfolio evolution. Our value-based planning process combines planning to address localized and reliability-related transmission issues including compliance with NERC reliability standards, with planning focused on regional and sub-regional solutions to economic and/or public policy issues. Localized planning focuses on the 10 year horizon while the regional planning aspect may look out 20 years or more. The process provides for a review of alternative solutions to identified issues, including non-transmission alternatives to projects identified to address reliability concerns.

Our innovative process was designed to ensure ongoing reliability while facilitating what are sometimes long lead time investments in an environment of policy uncertainty. The long-term aspect of the process uses a scenario based approach to mitigate that uncertainty. We look for projects that will provide value across a range of potential future states. These "no regrets" investments will be prudent no matter the actual future. Nearly $30 billion of transmission development has been identified in our planning process, with approximately $6 billion of that stemming from a long-term, regional portfolio of projects recommended in 2011.

- Challenges and Opportunities: Transmission investments in the MISO region have contributed significantly to a resilient MISO grid. As the generation portfolio continues to evolve to one of more intermittent and distributed generation, additional regional transmission will likely be needed to ensure system reliability and the most economic delivery of power. In a region spanning 15 states, diverse viewpoints make consensus on transmission needs, and how the costs should be allocated, challenging. That consensus becomes even more elusive as we seek to identify transmission needs inter-regionally. Overcoming those hurdles in a timely manner is imperative to ensure the grid of the future is in place to support the generation fleet of the future.
MISO Overview

Good morning Chairman Upton, Vice Chairman Olson, Ranking Member Rush, and members of the Subcommittee. I am Jennifer Curran, vice president of system planning at the Midcontinent Independent System Operator, Inc., or MISO. It is a pleasure to be with you today as you examine the state of our nation's electric transmission system. I hope the insights into how MISO facilitates transmission investments will be useful to your work of shaping U.S. energy policy.

I know this committee is interested in hearing about the facilitation of transmission system investments, including challenges associated with the planning and construction of new transmission lines, the effect of existing federal laws and regulations, and the consideration of non-transmission alternatives. Before I share MISO's insights on these matters, I would like to provide a little background about our organization.

The Federal Energy Regulatory Commission's (FERC) Order 2000, issued in 1999, established Regional Transmission Organizations (RTOs) to be independent entities that plan and operate the electric grid on a regional basis to maintain reliability and maximize efficiency. MISO was the first ISO to be recognized as an RTO, receiving FERC approval in 2001.

MISO is a 501(c)(4) not-for-profit social welfare organization with responsibility for ensuring the reliability of the high-voltage electric transmission system to deliver low-cost energy to consumers. The system that MISO manages is the largest in North America in terms of geographical scope, serving about 42 million people across all or parts of 15 states, stretching from the Canadian border to the Gulf of Mexico. Our energy markets are also among the largest in the world, with more than $25 billion in annual gross market charges. MISO also serves as the
reliability coordinator for MISO entities in these 15 states and the Canadian province of
Manitoba. A map of the MISO footprint is provided in the Appendix of this testimony.

Currently, the MISO region contains about 66,000 miles of high-voltage transmission assets with
an aggregate value of approximately $38 billion, as well as 175,000 megawatts of electricity-
generating capacity. MISO does not own any of these assets. Instead, with the consent of our
asset-owning members and in accordance with our FERC-regulated tariff, MISO exercises
functional control over the region’s transmission and generation resources with the aim of
managing them in the most reliable and cost-effective manner possible. The MISO Region is
predominantly comprised of traditionally structured and state regulated utilities. MISO has a
robust stakeholder process that allows asset owners, state regulators and all other stakeholders to
provide input and guidance to MISO on a regular and ongoing basis.

MISO’s mission is to work collaboratively and transparently with stakeholders to enable reliable
delivery of low-cost wholesale energy to the end use customers in our footprint. We achieve this
through innovative wholesale market operations and transmission grid planning. Through
execution of those functions and a focus on affordable energy we generate substantial benefits
for the end-use consumers served by our member utilities. MISO performs an annual study,
called the Value Proposition, to measure and quantify these benefits. In 2017 benefits totaled
more than $3 billion. Over the last decade, the cumulative value created is about $21 billion.

A portion of these benefits results from improved reliability and the optimization of all of the
region’s resources. However, the transmission system enables the majority of this value – over
$2 billion annually – by allowing the region to harness the substantial diversity benefits provided
by our expansive footprint. MISO’s region spans areas that can experience significantly different
weather at any given time. Demand in those areas peaks at different times. This allows for a
more efficient set of supply resources to be employed across those peaks than would be possible if demand peaked in all areas coincidently. The transmission grid provides the connections that allow low-cost energy to be transferred across the region and the deferral or avoidance of additional assets built by individual utilities. Our robust transmission system also provides the flexibility and adaptability needed to respond to the profound transformation taking place in the electricity industry.

**Evolving our Collaborative Planning Process to Accommodate Changing Generation Mix**

We are experiencing significant changes in the resource mix due to a combination of regulatory, political and economic factors. The abundance of low-cost natural gas, combined with legacy environmental regulations targeting emissions from coal-fired power plants and state policies promoting renewables, has put additional pressure on the traditional generation fleet. Additionally, energy-efficiency initiatives and “demand-side” programs that compensate customers for reducing their electricity use are growing in popularity, as are emerging technologies such as energy storage and distributed-energy systems like rooftop-mounted solar panels that allow homeowners to generate their own energy and sell, or receive credits for, excess power delivered back to the grid.

In the MISO region, which has historically been heavily reliant on coal-fired electricity generation, the impacts have been notable. For example, while coal-fired generation supplied 75% of the region’s electricity production as recently as 2011, that figure has fallen to less than 50% today. Conversely, while gas supplied just 6% of the region’s energy in 2011, it supplies...
about 27% today. And wind, which was essentially at 0% in 2005 and increased to 4% by 2011, is now at 8% and growing rapidly.

Our regional grid planning and facilitation of infrastructure investments have been key contributors to the region’s ability to effectively manage this resource portfolio evolution. The transition in the generation fleet over the last decade-plus has required that we advance our transmission planning process to ensure the grid enables and supports efficient delivery of power from the changing generation fleet while remaining reliable and resilient.

In the initial days of MISO planning, the focus was narrowly on reliability planning – “keeping the lights on” – with an emphasis on lowest initial transmission costs as the key driver of customer value; an approach largely consistent with utility planning in the traditional, pre-wholesale market era. However, MISO, in collaboration with our stakeholders, soon began to enhance our planning process to account for project benefits beyond just reliability, including market efficiency improvements and addressing public policy requirements and objectives. The resulting value-based process is designed to maximize value for consumers by identifying transmission which minimizes the combined costs of transmission, generation and the energy on the system, or in other words lowers the total delivered cost to consumers. Each cycle of the process is the culmination of a minimum of 18 months of collaboration between MISO planning staff and stakeholders and is documented in the annual publication of the MISO Transmission Expansion Plan (MTEP). In total, MISO has facilitated nearly $30 billion in total transmission investment since the first MISO Transmission Expansion Plan in 2003.

The process combines local and regional planning, bringing together needs and projects identified by local utilities with projects identified by MISO through our regional view of the system. Also factored in are policy and economic driven needs as well as expected generator
retirements and additions. Our process also covers the spectrum of near-term through long-term assessments of grid needs. A long term view is essential to ensure that transmission, which can have long lead times compared to some new generation options, does not become the barrier to flexible cost effective supply options that drive the largest part of customer electric bills.

Reliability planning generally has a near- to mid-term focus, looking at system needs in the 1 to 10 year horizon. These projects are justified by their role in complying with North American Electric Reliability Corporation reliability standards and are usually implemented in 2 to 5 years. The process of developing transmission projects includes, when appropriate, evaluation of alternative transmission projects to address issues. This includes evaluating non-transmission alternatives to ensure the best option is found. Market efficiency planning assesses expected system congestion over the 5 to 15 year horizon and develops transmission plans that reduce or eliminate congestion to enable customer access to lower-cost electricity through the market, recommending transmission projects only when the market efficiency benefits outweigh project costs. The handful of market efficiency projects recommended to date have varied in scale and scope and in some cases span multiple utility territories.

The long-term portion of the process looks out 15 to 20 years and is designed to periodically assess whether industry trends, such as those driven by changing economics and public policy objectives, are creating the opportunity or need for large-scale, regional transmission plans, and to inform nearer-term investment decisions. A scenario-based approach is employed, using a range of potential outcomes to “bookend” the uncertainty associated with various factors that can influence future system needs and thus transmission system design. Variables that are assessed across those different potential outcomes, or futures, include: fuel prices; electricity demand growth forecasts; generation retirements; state and federal policy impacts; and capital costs of
new generation. Futures are created or refreshed on an annual basis to provide a range of views on where the generation mix may evolve. Transmission is planned against these future scenarios, benefits are quantified, and projects whose benefits exceed costs by predetermined thresholds across the scenarios are considered no-regrets investments as they hold up economically against various potential future states, mitigating policy uncertainty.

The process concludes with cost allocation determined by assessment of beneficiaries consistent with the project driver or purpose. Where costs are shared between multiple parties, amounts are based on how much each entity benefits from the project. Ultimately, this question of who pays is the most challenging aspect of the regional planning process. Recommending any large transmission project requires a robust business case and a fairly high level of alignment among stakeholders; specifically, MISO stakeholders must be aligned in the belief that the project will provide the expected benefits, and that the expected distribution of the costs will fairly match the expected distribution of the benefits.

As states in the Midwest were passing Renewable Portfolio Standard mandates and goals, we recognized the growing need for transmission to more economically and reliably deliver the new resource mix that was occurring due to the policy changes. However, a lack of clarity regarding future policy direction and decisions made investing in long-lead transmission lines risky. The planning process described above, in conjunction with Midwest governor and state regulator leadership on assessing transmission need, and determining how to share the costs, provided a path to facilitate needed grid investments in spite of that uncertainty. The approach sought to provide regional backbone transmission in advance of a specific resource need (“build it and they will come”) to ensure greater efficiency in transmission build by thinking about the transmission need holistically. This approach also provided hope that transmission, which has a longer lead
time than generation, could be available to meet generator needs. As a result, in 2011 a portfolio of transmission projects known as Multi-Value Projects (MVP) was approved by the MISO Board of Directors. The approximately $6 billion dollar MVP portfolio, is made up of 17 projects, with most states in MISO's North and Central Regions being home to at least one. These projects provide reliability, congestion reduction and public policy benefits that are from 2 to 3 times greater than costs across the MISO footprint, and the costs are shared pro rata across MISO. In addition, at the time of approval it was estimated that they were expected to create about 28,000 direct construction jobs and around 50,000 total jobs.

**Planning for Continuing Fleet Evolution**

Continued execution of this process will be needed going forward, as the generation fleet continues to evolve. Earlier, I mentioned several factors that have been driving portfolio evolution. There is one more; end-use customer preference. Consumers no longer just want reliable, low-cost power - they also want it to be green and many want more control and ownership over powering their homes and businesses. Many utilities in MISO are developing long term resource plans which include increased levels of renewable energy, including in some cases distributed energy resources in the form of rooftop solar. New technologies impacting energy usage are emerging and expected to become competitive or have increased levels of adoption, including energy storage, digital devices such as smart thermostats and electric cars.

The amount and type of resources requesting to interconnect to our system suggest the changes in front of us. MISO currently has over 90,000 MW of requests in our generator interconnection queue, an 80% increase just this year. To get a sense of scale, consider that the total installed generation capacity in MISO today is 175,000 MW. Utility-scale wind and solar resources
represent over 85% of the current MW seeking to connect. While many of the projects in the queue will not be built, even a portion will continue to drive changes in the operating profile of the MISO fleet.

The continued growth of utility scale wind and solar as well as distributed generating sources will drive the need for more transmission as electricity generating unit scale decreases and intermittency grows. The ability not only to meet peak demands, but to move bulk power from resource areas to load centers across the footprint in all hours of the day will be needed to improve reliability and efficiency of this new resource fleet. Regional transmission will play an essential role in optimizing the natural and geographic diversity of these resources.

Large regional investment tends to be cyclical. In the case of the MVP portfolio, the projects were designed to address the amount of renewable energy required by the Renewable Portfolio Standards that were in place in 2011. The transmission itself was planned for construction over many years; the final lines are expected to be complete by 2023. Given these types of timelines, it is prudent to evaluate the next set of regional investments required to ensure reliable, resilient and efficient energy delivery.

While design and approval of the Multi-Value Project portfolio took time and compromise, ultimately stakeholders across the region were able to find common ground on the need for the projects, the benefits they would bring, and the need to share the cost. Since the MVPs were developed, a number of things have changed that increase the complexity of the task in front of us. The 15 states and dozens of utilities serving the over 42 million people that make up MISO have a much wider range of resource options available to address their respective policy and economic drivers. The sheer size of the footprint has us revisiting the question of how widely benefits spread, and thus costs should be shared. In most places the amount of electricity needed
at peak times is not growing, and the increase of distributed energy resources makes forecasting what type of electricity needs to plan for much more challenging. The different aggregate operating profile of the new resource mix suggests that, in order to safeguard resilience, there is a need for new benefit measures related to flexibility for the transmission business case. Although MISO's administration of the competitive bidding process has been successful, the introduction of competitive bidding for transmission through FERC Order 1000 created new business interests and created different paradigms for projects with cost allocation versus those without. An increased focus on interregional transmission planning has further expanded the set of interests we seek to align, and highlighted some fundamental differences in viewpoint around how to most efficiently operate the transmission system to maximize the value of the existing assets.

For reasons such as these, along with a broad sense of uncertainty for the future, finding consensus among so many diverse viewpoints on system needs, and who should pay for those system changes, is a significant challenge in planning for additional large scale transmission investment in the MISO region. Nonetheless, we continue to study different aspects of the future fleet to assess the potential issues and clarify transmission needs. Ultimately, we remain focused on transmission that provides value to users of electricity in excess of the costs that new transmission would bring. Timely understanding of what transmission will provide value, no matter what the future holds, is imperative to ensure the grid of the future is in place to support the generation fleet of the future.

MISO, as an RTO, has a unique role in the industry and brings a unique perspective to the challenges we face. We are policy neutral – we don't advocate for any particular policy. MISO instead works to inform policy makers about the impact of planned approaches. We then work
with the states, utilities and all other stakeholders in our regions to ensure any policy is implemented reliably and efficiently. MISO has utilized this role to create $21 billion in benefits for our region while positioning our members to effectively navigate the continuing evolution of the industry. We are committed to continued facilitation of grid investment through innovative planning and development to optimize the changing resource portfolio and we appreciate the opportunity to help inform the discussions that will shape the path forward.
APPENDIX

MISO Footprint
Mr. OLSON. And thank you, Ms. Curran. We will talk about Beer Bike and Baker 13 offline.

Our next witness is Dr. Ralph Izzo. He is the CEO of the Public Service Enterprise Group.

Dr. Izzo, you have 5 minutes.

STATEMENT OF RALPH IZZO

Mr. IZZO. Good morning, Mr. Chairman, Ranking Member Rush, members of the subcommittee, as well as full committee Ranking Member Pallone, who has had a long and exemplary career serving the people of my home State, New Jersey.

I am pleased to provide my point of view on the importance of continuing to strengthen and modernize electric infrastructure. Today I will highlight one Federal policy that stands as an impediment to that goal and should be repealed, that being FERC Order 1000.

I am here representing the Public Service Enterprise Group and our subsidiary, PSE&G, a 114-year-old company that is New Jersey’s largest electric and gas utility. PSE&G owns around 1,600 circuit miles of transmission operated by PJM Interconnection.

Despite the fact that PSE&G has been named the mid-Atlantic’s most reliable electric utility for 16 years in a row, much of our electric infrastructure is old. While it has helped power the industrial Northeast for nearly a century, in recent years we have had to work to replace, upgrade, modernize, and sometimes move parts of the grid in order to ensure our system can withstand extreme weather events and other threats, for even as our customers are using less electricity, their reliance on it has never been greater.

Of course, we don’t have a blank check. Our investments must be prudent. Over the past 10 years we have made improvements that have reduced unplanned transmission outages by over 80 percent. So the customer benefit is clear.

Transmission investment has been helped by Federal policies that have recognized the importance of transmission and the risk in building large projects. However, Order 1000 stands out as a policy that undermines these efforts.

Enacted by FERC in 2011, Order 1000 was touted as landmark reform that would promote efficient and cost-efficient transmission planning and remove barriers to development. But in the 7 years that we have been living under Order 1000, the promised efficiency looks more like confusion, controversy, and chaos.

Regional grid operators have begun to voice their views. PJM CEO Andy Ott last year called Order 1000, and I quote, “a solution in search of a problem that is creating more of a challenge.” Southwest Power Pool CEO Nick Brown said it created, “more overhead and more uncertainty.”

Our main experience with Order 1000 has been through a competitive solicitation launched by PJM in 2013 for a project to solve voltage issues in southern New Jersey. To call the process a mess would be generous. PJM made an initial decision and then reversed itself. Disputes cropped up between States and stakeholders that the RTO had to mediate.

PJM found itself having to make judgments outside its expertise, for example, on which alternatives might secure environmental
permits or how to interpret the fine print and exclusions when a developer says it will cap construction costs.

Five years into the planning process, we still do not have a constructed project to address a major need on this part of this grid. And across the country, other red flags continue to appear. No region outside organized markets have even attempted to administer an Order 1000 bid. The Southwest Power Pool spent $5 million on a competitive process for an $8 million project that was deemed unneeded and never built. The California ISO awarded a project to a partnership between a foreign developer and another entity, only to see the developer go bankrupt.

Mr. Chairman, after 7 years these can no longer be called growing pains. But even beyond the chaotic implementation of Order 1000, there lurks a more fundamental concern. Order 1000 tends to drive short-term, Band-Aid fixes for the grid. Projects that solve multiple problems and provide long-term value tend not to move forward because they are ruled out as being too costly.

Competition is a positive force. But the goals must be set to achieve the outcomes we want. People and businesses depend on an efficient electric system that is resilient for the long-term against an array of very real threats. Leaving Order 1000 in place risks our ability to achieve that end.

Thank you.

[The prepared statement of Mr. Izzo follows:]
Good morning Chairman Upton, Ranking Member Rush, Ranking Member Pallone of the full Committee and my home state of New Jersey, and members of the Subcommittee. My name is Ralph Izzo and I am the Chairman, President and Chief Executive Officer of Public Service Enterprise Group, a diversified public utility holding company headquartered in Newark, New Jersey that owns generation, electric and gas transmission and distribution facilities.

Our utility PSE&G is a 114-year old company and is the largest electric and gas distribution and transmission utility in the State of New Jersey. We serve 2.2 million electric customers. We own approximately 1567 circuit miles of transmission that is operated by PJM Interconnection, LLC (PJM), the independent grid operator in a region that spans 13 states and the District of Columbia. PSE&G has received the prestigious ReliabilityOne Award as the most reliable electric utility in the Mid-Atlantic region for 16 years in a row.

Thank you for the opportunity to speak this morning on the future of the transmission grid, and what it will take to ensure we have the policies in place to continue to drive the right investments to serve our customers. I want to first outline the value proposition to customers of our efforts to modernize and strengthen the transmission grid. Then I'd like to focus on existing federal policy. While many steps have been taken to encourage transmission investment in recent years, FERC's Order 1000 stands out as a measure that has hindered efficient transmission planning and should be repealed.

PSE&G's first concern in the area of transmission is, and has always been, the long-term reliability of the grid. We are a franchised public utility with an obligation to serve under state law. If the lights go out in New Jersey, we are the ones that customers call, and we are the ones...
elected leaders call. At the same time, PSE&G is always seeking to make cost-effective investments. We know we do not have a blank check – we must answer to our regulators and customers. Our investments must be prudent.

Let me give you a sense of the investments PSE&G has been making in our system, and what the value of these investments has been to our customers. PSE&G has been actively involved in upgrading and adding to its transmission system over the last several years. For instance, we are in the process of converting our aging 26 kV system to a more robust 69 kV system. Our 26 kV system was built in the 1920s and was fine for its time but is not adequately suited to address long-term customer needs. For our new 69 kV facilities, we are using modernized equipment and stronger poles with a higher capacity for moving power throughout our system.

Our investments have also included large and challenging Extra High Voltage (EHV) transmission projects covering hundreds of miles in some of the most densely populated areas in the nation. This includes the Susquehanna-Roseland project completed several years ago by PSE&G and PPL, which replaced 90 year-old towers along the transmission backbone that powered the industrial northeast corridor nearly a century ago. We have also constructed many smaller projects on city streets and in tight areas that put us in close proximity to residents, including replacing 1920s vintage poles and stations before a reliability threat presents itself. And finally, Superstorm Sandy in 2012 devastated New Jersey and presented extraordinary challenges to the transmission and distribution systems in our area, prompting us to replace, harden, smarten, and even move electric infrastructure to improve the resilience of the system against the extreme weather events that are becoming all too common.

Collectively, these projects have achieved multiple objectives – addressing reliability concerns, improving resiliency, reducing congestion and increasing access to lower cost generation resources.

But just what is the value proposition to customers of these investments? The transmission infrastructure that moves vast amounts of electricity is essential to economic well-being and quality of life. As President George W. Bush said around the time the Energy Policy Act was signed into law, “We have modern interstate grids for our phone lines and our highways. It’s time for America to build a modern electricity grid.” Transmission remains absolutely critical from both an economic standpoint and from a reliability and security standpoint.

When the power is out, the results are economically devastating. In 2017 alone there were sixteen (16) costly weather and climate events in the United States and Puerto Rico, including Hurricanes Harvey, Irma and Maria. And these 16 events cost over $300 billion. While we cannot control the weather, we can proactively continue to make investments that will better prepare our customers for these events by both preventing outages and minimizing their duration. Superstorm Sandy cost New Jersey customers 775 million hours of lost electricity service. Yet, due to our investments in our transmission system, during the period between

2
2013 and 2017, the number of unplanned outages on the transmission system (138kv and above) declined from 111 to 44. Thus, our investments have paid dividends for our customers.


Given that we are seeing more and more extreme weather, continued resilience investments are vital. As FERC Commissioner Richard Glick recently noted, "the record demonstrates that, if a threat to grid resilience exists, the threat lies mostly with the transmission and distribution systems, where virtually all significant disruptions occur. It is, after all, those systems that have faced the most significant challenges during extreme weather events." Although I am sure Commissioner Glick was not suggesting we should ignore generation resiliency, he rightly identifies that transmission resilience investments are needed to ensure that the lights remain on, that trains and planes can run, that businesses can operate and that people can go to work.
There is no better testament to the criticality of our grid than the fact that bad actors are increasingly trying to take it down. As FERC Commissioner Cheryl LaFleur testified before this Subcommittee a month ago, "Hacks on the grid are constant. Every year, electric grid attacks are either a slight majority or slightly below 50 percent" of all cyber attacks in the United States. PSE&G is working closely with PJM and with other transmission owners in the region to ensure that the grid remains secure from physical and cyber security threats. This will not be an easy or static fix, and will require ongoing investment to build redundancy into the system.

Any period of major infrastructure development and replacement raises questions about the cost of these investments; these questions are appropriate, and are an important part of balancing resiliency and cost. And yet, as the data above suggests, not investing in our critical infrastructure will cost customers far more in many cases than making the initial investments in upgrades. In addition, notwithstanding my company’s investment in needed transmission over the past several years, the typical PSE&G residential customer electric bill has actually declined 7% from its 2010 level due to lower prices for electric supply. This makes for an opportune time to make needed investments.

In our region, transmission investments have the corollary benefit of reducing congestion on the grid, which in turn further lowers costs for customers. In PJM’s Independent Market Monitor’s (IMM) 2017 State of the Market Report, the IMM noted that, while in 2008, congestion costs totaled 6.0% of PJM billing, in 2017, the percentage had declined to 1.7%.
Federal Policy

Mr. Chairman, there is no question that transmission investment over the past decade or more has been supported by many federal policies that explicitly recognize the importance of transmission, as well as the inherent risk to investors of large transmission projects. By contrast, other more recent policies such as FERC's Order 1000 have introduced complexity and confusion in the transmission planning process, and should be re-examined before its worst consequences begin to manifest themselves to consumers.

By way of history, we all remember the Northeast Blackout in August 2003. This event knocked out power across the Eastern United States and parts of Canada, affecting approximately 50 million people and resulting in 592 million hours of lost electricity service. Shortly after the Blackout, Congress enacted the Energy Policy Act, articulating a statutory directive to bolster investment in the Nation's transmission infrastructure, reduce congestion and lower overall cost to consumers. Congress designated the North American Electric Reliability Corporation (NERC) as an Electric Reliability Organization, with the authority to issue mandatory reliability standards and impose them on the industry. Implementing the Energy Policy Act, FERC then issued an Order establishing important transmission rate incentives that would be available to transmission owners to stimulate investment.

In 2011, a federal Rapid Response Team for Transmission (RRTT) was formed, made up of nine agencies, to accelerate transmission development by streamlining the federal permitting process. The RRTT found that seven projects, including the PSE&G/PPL Susquehanna-Roseland project, were of national priority. Finally, in 2016, the DOE released a Final Rule to streamline and expedite transmission projects, viewing this action as an important step to spur continued transmission development.

All of these steps have been important, and efforts in these areas should continue. But I'd like to turn my attention to a more recent policy initiative that stands in stark contrast to these other helpful measures: that is the misstep known as FERC's Order 1000. Enacted in 2011 by FERC under then Chairman Wellinghoff, it was touted as a landmark reform that would "promote efficient and cost-effective transmission planning..."; "remove barriers to development of transmission facilities..." and "promote competition in regional transmission planning processes."

My company opposed Order 1000 when it was initially proposed, because we felt it was a misguided effort to carry out climate and environmental policy through planning of the transmission grid. While we wholeheartedly support the agenda to move toward cleaner, lower-emitting sources of energy, our view was that upending the transmission planning process that worked well was not the right answer and would create more problems than it solved.
Far from the promised efficiency, what Order 1000 has sown in transmission planning in the PJM region is political discord among states; confusion as to the process among transmission planners, potential transmission investors and grid operators; wasted dollars by all involved — and predictably, delay. It’s no wonder that the vast majority of transmission being built in PJM today is occurring outside the Order 1000 process.

Our most direct experience with transmission planning in the era of Order 1000 has been a competitive solicitation process run by the PJM grid operator for a project called Artificial Island, a needed transmission upgrade to address voltage issues at PSEG’s 3,500 megawatt nuclear site in Southern New Jersey. PSE&G has been selected to build a sizeable portion of the line but not the entire project.

PJM opened the bidding on the Artificial Island project in April 2013. To call the process chaotic would be generous. We have seen the RTO make an initial project selection only to later reverse itself. We have watched the RTO attempt to arbitrate disputes between states. At one point the RTO had to suspend and reboot the entire solicitation. We have seen the RTO try to scrutinize, interpret and validate the fine print and exclusions when a developer says it will adhere to a cost cap for construction. We have seen the RTO try to play the role of mediator between stakeholders. We have seen the RTO try to pre-judge the feasibility of certain projects based on their ability to secure environmental permits.

Mr. Chairman, very few of these are appropriate roles for a regional grid operator. They don’t have the resources, and in many of these instances they don’t have the expertise, nor should they. It should be no surprise that this process is now in year five and has yet to yield a constructed transmission solution to solve the reliability problem on this section of the grid.

Yet if it were just a matter of what Order 1000 is not achieving, it might be tempting to leave it intact and just find a work-around, and turn our attention to other problems.

But it’s important to also look at how Order 1000, if left on the books, would change the very nature of transmission investment, not necessarily with the long-term need of customers in mind. The fact is, Order 1000 even at its best would not facilitate the type of robust transmission solutions that provide long-term value to customers. A project such as Susquehanna-Roseland, which resolved 23 PJM-identified reliability violations, replaced aging infrastructure and reduced congestion, would not ever emerge from an Order 1000 competitive solicitation because it would be deemed to “cost” too much. Order 1000 drives investment to the band-aid, shorter-term solution, not the solution that is most cost-effective for customers in the long run. This hardly seems the path to effectively address the risks customers face from an aging infrastructure, extreme weather, cyber and physical security threats and the urgent need for a diverse and resilient generation supply.

Some may discount our observations on Order 1000 as sour grapes over a single project outcome. But the truth is that since the adoption of Order 1000 the better part of a decade ago,
several independent grid operators have recognized the need to limit its application, and many have started to share their views more publicly. Last year PJM CEO Andy Ott stated that the Order is "almost like a solution in search of a problem. It's actually creating more of a challenge to investment."

Mr. Ott’s sentiments were echoed by Southwest Power Pool CEO Nick Brown who remarked that the Order “created more overhead and more uncertainty at a time when we didn’t need more overhead in order to invest in transmission.”

In fact, the embrace of Order 1000 across the country has been tepid at best:

- No planning region in the U.S. that is outside of an organized RTO/ISO market has opened up a single competitive transmission bidding opportunity post-Order 1000.
- One ISO region – the ISO-New England – has not opened a single competitive solicitation.
- The New York ISO began its competitive transmission process in August of 2014. In October of 2017 it awarded its first project. Its second project has yet to be awarded, almost four years after NYISO began its efforts.
- The Southwest Power Pool has opened one solicitation, resulting in an $8 million project that was ultimately determined not to be needed and the incurrence of approximately $5 million in administrative costs to run the bidding process.
- The Mid-Continent ISO has opened two bidding opportunities. One resulted in the award of a $46 million project after a year-long process. The other is ongoing at the present time.
- The California ISO has not opened a competitive solicitation since 2016. Moreover, in 2015, the California ISO awarded a competitive project to a partnership between a foreign developer and another entity, and the developer subsequently went bankrupt.

Former FERC Commissioner Tony Clark, my fellow panelist, recently stated, "[F]or all its good intentions, [Order 1000] is today a rule that has largely fallen short of accomplishing its goals. Unfortunately, the failure of it to fulfill its potential has not come without costs. ... [N]ow is a good time for the Commission to consider an Order No. 1000 reassessment.”

I’d like to take this sentiment a bit further and suggest that it should just be repealed. Order 1000 has been on the books for almost 7 years. Its problems can no longer be called growing pains. I would suggest that at a minimum and right away, FERC should "hit the pause button" on Order 1000 until and unless the planning regions can demonstrate significant benefits flowing from the Order. There should be no further Order 1000 activity in the form of open solicitations or windows until such a demonstration has been made.
Conclusion

In conclusion, PSE&G wholeheartedly supports the bipartisan goal of investing in this nation's infrastructure, including our transmission grid. We are deploying considerable capital today to this end, and we stand ready to work with Congress, FERC and many others on policies that will ensure we can do so in a way that delivers the most long-term value, and facilitates the most resilient and most efficient electric system possible for our customers. We need to take a hard look right away at how Order 1000 is impeding these goals.

Thank you and I look forward to taking your questions.
STATEMENT OF JOHN TWITTY

Mr. Twitty. Chairman, indeed, I do.

Well, good morning, Mr. Chairman and members of the subcommittee. I am John Twitty, Executive Director of TAPS, the Transmission Access Policy Study Group. Our association has been active here in the Capitol and at FERC protecting the interests of transmission-dependent utilities. We represent municipal utilities, joint action agencies, a rural electric cooperative, and an investor-owned utility, serving about 1,200 utilities with retail customers in 35 States.

As load-serving entities dependent upon the transmission facilities of others, TAPS members recognize the importance of a robust grid and have long advocated policies to get needed transmission built, but are keenly aware that expansion must be achieved at reasonable cost.

By enacting Section 217(b)(4) of the Federal Power Act of 2005, Congress gave FERC clear instructions on transmission planning and expansion. FERC is directed to facilitate planning to meet the reasonable needs of load-serving entities and enable load-serving entities to secure long-term firm physical or equivalent financial rights for long-term supply power arrangements made, or planned, to meet their service obligations.

These directives translate into steps FERC can and should take regarding transmission planning and investment. But that is not happening to the degree necessary to meet Congress’ mandate. First, the grid has to meet the needs of load-serving entities. Although FERC has established rules for an open and transparent transmission planning process, even FERC has recognized that this is not happening consistently.

Second, we need to be sure our investment in new transmission is appropriate, consistent with Section 217’s focus on the reasonable needs of load-serving entities. TAPS members have experienced rapid increase in transmission cost. While a portion of the increase is no doubt justified, transmission has become an investment magnet. The potential for guaranteed incentive-elevated returns on equity on low-risk transmission assets may spur invest-
ment that is not necessary. While we support FERC’s ground-up consideration of grid resilience, it should not become a blanket justification for excessive investment.

Third, FERC has fallen short in fulfilling Section 217’s directives regarding long-term transmission rights, particularly as to the capacity associated with long-term power supply arrangements on which load-serving entities rely for resource adequacy. This exposes load-serving entities to increased cost, especially if the RTO choices of large transmission owners have left them with loads and resources in multiple RTOs. It also makes new investments riskier.

Fourth, above-cost incentives are not needed to attract investment. There is no shortage of entities seeking to invest in low-risk transmission assets at FERC’s base equity return that is intended to reflect the cost of attracting capital. There is no need for incentive rates of return, much less to expand their availability beyond opportunities provided under current FERC policy. Those seeking transmission incentives should not be permitted to turn away load-serving entities in the footprint seeking to make their load ratio investment in the grid.

Finally, the transmission planning process can also be a more effective vehicle for inclusive transmission investment. Non-incumbent transmission developers, especially those that accommodate participation by small load-serving entities, should have a fair opportunity to develop needed new transmission.

Congress should encourage the Commission to reinvigorate the Order 1000 competitive transmission development process in a manner that will promote joint transmission ownership, as well as to use competitive discipline to curb rising transmission cost.

At TAPS, we want to be part of the solution so long as the needs of our customers are met. And I look forward to this discussion.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Twitty follows:]
Thank you for the invitation to testify regarding the important topic of Examining the State of Electric Transmission: Investment, Planning, Development and Alternatives. My name is John Twitty, and I am the Executive Director of TAPS—the Transmission Access Policy Study Group, an association of transmission dependent utilities in more than thirty-five states, promoting open and non-discriminatory transmission access.¹ Our membership includes municipal utilities, as well as a cooperative and an investor-owned utility. Some TAPS members are in areas served by a regional transmission organization ("RTO"), and a number of members have loads and diverse resources in multiple RTOs due to the RTO-membership decisions of large transmission owners. Other TAPS members are located in non-RTO regions.

As load-serving entities (utilities with a legal or contractual obligation to serve customers) dependent on the transmission facilities largely, if not entirely, owned by others, TAPS members recognize the importance of a robust transmission grid to competitive generation markets, and have long advocated policies to get needed transmission built.² But as transmission customers that must pay transmission rates to...
serve their load, TAPS members are also keenly aware of the need to ensure that necessary transmission expansion is achieved at reasonable cost. Consumers and businesses should not be burdened with transmission rates that are elevated by above-cost incentives that are not needed to attract investment or that fund unnecessary facilities.

We appreciate your focus on these issues that are crucial to the ability of load-serving entities to continue to provide the reliable, affordable electric service required for our Nation’s social and economic vitality. My comments will focus on the direction Congress has already provided to the Federal Energy Regulatory Commission ("FERC" or "the Commission") through Section 217 of the Federal Power Act ("FPA"), and outline other steps that should be taken to better achieve that provision’s goal of a robust transmission grid at reasonable cost designed to meet the reasonable needs of load-serving entities.

I. CONGRESS HAS INSTRUCTED FERC THAT GRID PLANNING AND EXPANSION SHOULD FOCUS ON THE REASONABLE NEEDS OF LOAD-SERVING ENTITIES

Section 217(b)(4) of the FPA, enacted as part of the Energy Policy Act of 2005, provides key congressional directives to FERC on transmission planning:

The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

Section 217(b)(4) thus established Congress' clear guideposts to FERC as to transmission planning and expansion. FERC is directed to:

a. Facilitate planning to meet the reasonable needs of load-serving entities to satisfy their service obligations; and

b. Enable load-serving entities to secure long-term firm physical, or equivalent financial, rights for long-term power supply arrangements made or planned to meet those service obligations.

As recognized by the D.C. Circuit, “Section 217(b)(4) creates a requirement for the Commission . . .”3

Section 217(b)(4)'s directives translate directly into steps FERC can and should take regarding transmission planning and investment to assure that Congress’ express intent is achieved; but that is not happening to the degree necessary to meet the Commission’s obligations under the law. I will discuss several of these below.

A. **Load-serving entities should have a seat at the table to ensure their reasonable needs are planned for**

Through its Order 890 and Order 1000 rulemaking proceedings, FERC has required an open and transparent transmission planning process. In doing so, it has expressly recognized that this process is intended to be consistent with Section 217(b)(4).4

The Commission recently recognized the importance of open, inclusive and transparent processes to transmission planning when it found the planning process undertaken by certain PJM transmission owners to be unjust and unreasonable, and

---


4 Order 890-A, P 24 (stating that to "appropriately balance the needs of these various classes of transmission customers, including the transmission provider's native load, [load-serving entity] customers serving network load, and other firm users of the system . . . is entirely consistent with, if not expressly required by, FPA section 217").
inconsistent with the transparency and coordination principles required for a compliant planning process. As a result of these deficiencies, stakeholders did not have an opportunity to have meaningful input into the planning process. Similar concerns about the lack of transparency in the transmission planning process have been raised in other regions. For example, stakeholders in California have filed a complaint at FERC alleging that Pacific Gas and Electric is improperly developing 80 percent of its transmission projects without stakeholder input.

TAPS supports the Order 890 and 1000 planning requirements, and urges Congress to continue its appropriate role in conducting oversight of FERC to ensure that these requirements are met; more is needed to ensure that Congress’ Section 217(b)(4) mandates are fully satisfied. Specifically, more should be done to encourage joint transmission ownership arrangements. Under such arrangements, load-serving entities embedded in the transmission system have the opportunity to invest in their load-ratio share of the transmission grid; they have a seat at the “grown up” table in the planning process, so they can play an integral role in ensuring their load is being properly served with necessary infrastructure. Non-profit, public power load-serving entities also have no interest in “gold-plating” the transmission system, so including them in the transmission planning process helps to assure that the grid is robust and reliable, without imposing unnecessary costs.

---

Such arrangements have a long track record of ensuring all load-serving entity needs are fully and fairly considered in the planning process. They also bring together diverse interests to expedite state siting and local permitting processes, thereby facilitating the construction of needed transmission. As detailed in TAPS' White Paper and Position Paper, such arrangements can take the form of an inclusive transmission-only company (or transcos), such as the Vermont Electric Power Company, formed in 1956, and the more recent example of the 2001-formed American Transmission Company in Wisconsin, Michigan, Minnesota, and Illinois.7 Inclusive shared system arrangements are another option with a long history of success in Georgia, Indiana, Minnesota, North Dakota, and South Dakota, and have more recently been established in Connecticut. Joint ownership arrangements also include inclusive arrangements for new facilities, such as CapX2020, a joint transmission-planning process in the northern Midwest. CapX consists of eleven investor-owned, municipal, and rural cooperative utilities in Minnesota, North Dakota, South Dakota, and Wisconsin that have jointly planned needed transmission upgrades and have opportunities to jointly own those facilities. CapX investment now amounts to some $2 billion and includes four 345-kV transmission lines and a 230-kV line.

The Commission itself has repeatedly recognized the value of these arrangements. For example in Order 1000, the Commission stated:8

> We reiterate here our statement in Order No. 890 that we believe there are benefits to joint ownership of transmission

---

7 GridLiance's recent efforts to partner with public power and cooperatives in transmission investments provide another example of this type of arrangement.

8 Order 1000, P 776 (citing Order 890, P 593). See also Order 1000-A, P 81 ("[T]he Commission supports investment in transmission infrastructure by transmission dependent utilities.").
facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers.

The Commission commented favorably on the benefits of such arrangements in its rulemakings implementing FPA Section 219's authorization of incentive-based rate treatments. The Commission's 2012 Policy Statement on Incentives "encourages incentives applicants to participate in joint ownership arrangements and agrees . . . such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks." The Policy Statement emphasizes risk-reducing (rather than rate-increasing) incentives by stating the Commission's expectation that applicants take all reasonable steps to mitigate risks before they seek an incentive return on equity, noting that "[e]vidence regarding whether an applicant for incentives considered joint ownership arrangements may be relevant in assessing whether the applicant took appropriate steps to minimize its risks during project development." This encouragement, however, has not led to tangible, real world progress.

**B. Above-cost rate incentives do not advance the objective of planning for a grid right-sized to meet the reasonable needs of load-serving entities**

Section 217(b)(4) expressly anchors planning and expansion in meeting the reasonable needs of load-serving entities. Congress did not mandate a "build it and they

---

9 See, e.g., Order 679, P 354 ("[P]ublic power participation can play an important role in the expansion of the transmission system. . . . Encouraging public power participation in [new transmission projects] is consistent with the goals of Section 219 by encouraging a deep pool of participants.").


11 Id. at n. 33.
will come” approach. TAPS advocates for a robust grid that supports competitive markets and long-term transmission rights to support long-term power supply arrangements to meet service obligations, but is concerned about mounting transmission rates.

TAPS members in a number of regions have experienced rapid increases in the cost of transmission service. For example:

- American Electric Power, a utility serving customers in eleven states with an over 40,000-mile transmission network, has increased its zonal transmission rate from $27/kW-year to $54/kW-year between 2012 and 2017—meaning rate increases of about 15 percent per year. For PPL, another large transmission provider in PJM, the zonal transmission rate increase over the same period was even larger. It went from $24/kW-year to $61/kW-year, growing at about 20 percent per year.

- In New England, total regional network service transmission rates have increased from about $15/kW-year in 2003 to just over $103/kW-year in 2016, an average annual increase of about 16 percent.

- In the Southwest Power Pool, which extends from North Dakota to the Texas Panhandle, the average annual rate increased from $5.97/kW-year in 2013 to $13.14/kW-year in 2018. That means an average annual increase of about 17 percent.

While a portion of the increased transmission rates is justified by the need to maintain reliable service, TAPS is concerned that transmission has become a magnet for excessive investments. The potential for guaranteed, incentive-elevated returns on equity on transmission facilities that are low-risk investments, with full cost recovery ensured by formula rates, will encourage over-investment. FERC’s allowance of forward-looking formula rates eliminates any potential for returns to be diminished by regulatory lag. We attribute to this low-risk, high-return investment vehicle the increasing trend of transmission owners actively seeking to increase their regulated transmission
investments, while reducing their exposure to the risk associated with generation investments, particularly in deregulated markets. 12

The FERC-allowed ensured returns on low-risk transmission investments are so rich that large transmission owners are reluctant to share the investment opportunity with others. In fact, transmission owners have litigated against each other for the lucrative opportunity to build. 13 Despite Commission recognition of the benefits of joint ownership arrangements, large transmission owners have similarly rejected TAPS members’ efforts to secure joint transmission ownership opportunities. As a result, small load-serving entities cannot offset the increasing transmission rates they must pay others against transmission revenues received for their transmission investment. Rather, the businesses and consumers that depend on these entities for service bear the full brunt of rising transmission rates.

TAPS is also concerned that the high-equity-return-fueled interest by transmission owners and others in investing in low-risk transmission may spur investment that is not necessary, or which—particularly given the changes underway in our electric system, including flat or declining load growth and the emergence of distributed energy resources—could become a stranded cost burdening our economy and our citizens as the industry further evolves. We support the Commission’s ground-up examination of

potential grid resilience issues, and we recognize the importance of a robust transmission system to resilience.

However, “resilience” should not be permitted to serve as a blanket justification for excessive investment. There will always be opportunities to make the grid more resilient. The crucial question is what is the appropriate level of resiliency, consistent with Section 217(b)(4)’s directive to FERC to facilitate planning for the reasonable needs of load-serving entities, allowing them to continue to provide the reliable, affordable electric service on which our businesses and consumers depend.

C. Transmission planning should honor and support long-term rights for load-serving entities’ long-term power supply arrangements

As Congress recognized in enacting Section 217(b)(4), load-serving entities’ long-term power supply arrangements are a key contributor to reliability and resource adequacy, and should be supported by firm physical or equivalent financial transmission rights. Long-term power supply arrangements include not only the moment-by-moment deliveries of energy, but also the power or capacity to make the deliveries necessary for resource adequacy. FERC’s pro forma open access transmission tariff that has been in place since its seminal Order 888 rulemaking in the late 1990s defines firm transmission service as providing for delivery of capacity and energy.14

While FERC has implemented Section 217(b)(4), in part, by enabling load-serving entities in RTOs to secure long-term transmission rights (or equivalent financial rights) for the delivery of energy under their power supply arrangements, FERC has

14 Order 888-A, FERC Stats. & Regs. ¶ 31,048, at 30,530 (Order 888-A tariff § 28.3); id. (Order 888-A tariff § 28.2).
refused to apply Section 217's directives to ensure the delivery of the capacity associated with these power supply arrangements. As a result, load-serving entities may be unable to rely on these long-term power supply arrangements to meet resource adequacy requirements, even though their long-term firm transmission arrangements expressly provide for the delivery of both capacity and energy. Instead, these load-serving entities are effectively forced to purchase, at potentially higher prices, other capacity at their load.

This disruption of load-serving entities' reliance on their long-term power supply arrangements, including investments in long-lived generation, is a particular problem where a load-serving entity's generation is separated from the load to which it has long been dedicated by a "seam" created by the RTO choices of the large transmission owners in which the load-serving entity's load or generation is embedded. Although the load-serving entity's generation and load may have been in the same RTO when its long-term generation commitments were made, the ability of large transmission owners to switch RTOs (or join or leave an RTO) without protecting embedded load-serving entities from any adverse impacts may later separate the small load-serving entity's generation from the load to which it is dedicated. The Commission's acceptance of new RTO resource adequacy requirements that fail to fully preserve and honor the load-serving entities' long-term rights to firm delivery of its capacity to its load undermines these long-term


16 See PJM Interconnection, L.L.C., 161 FERC ¶ 61,197, PP 175, 176, 178 (accepting new deliverability assessments that could cause load-serving entities to be deprived of their long-term resources supported by long-term firm transmission rights, effectively putting such load-serving entity uses that should have been planned for on the margin).
power supply arrangements and improperly leaves such small load-serving entities (and the businesses and consumers which rely on them) exposed to increased costs and risks.

II. KEY TAKEAWAYS

A. Congress should reaffirm the importance of FPA Section 217(b)(4), and take FERC to task for not fully embracing its dictates

As I've highlighted above, FPA Section 217(b)(4) provides a crucial framework for assessing policy choices pertaining to transmission planning and investment. In calling for planning for load-serving entities' reasonable needs, including long-term transmission rights for long-term power supply arrangements, the statute provides essential focus and constraints on the planning process. It points toward an inclusive planning process that produces a right-sized grid that meets the needs of load-serving entities to provide reliable service, at an affordable cost, to businesses and consumers. And it cautions against a planning process that produces grid investment that is not necessary to meet those reasonable needs. The Committee should exercise its appropriate oversight authority to ensure that FERC takes seriously Section 217’s guideposts as it makes policy choices regarding planning and investment in the grid.

The Committee should also investigate whether Section 217(b)(4)’s second directive—that the Commission enable load-serving entities to secure long-term rights (physical or financial) for the delivery of their long-term power supply arrangements’ energy and capacity—has been adequately adhered to. The Commission’s failure to fulfill its mandate with regard to delivery of capacity, a key component of long-term power supply arrangements, undermines the very arrangements Section 217(b)(4) seeks to support and honor.
B. Equity incentives should be limited

As I explained, incentive rates of return—that pay investors more than the “base return on equity” (i.e., the level required to attract and maintain investors)—place a heavy burden on the nation’s businesses and consumers with no corresponding benefit. There is no shortage of entities seeking to invest in transmission, and thus no need for incentive rates of return. These incentive rates of return encourage over-investment in the grid and incentivize the exclusion of small load-serving entities from being allowed to make their share of needed grid investment, to the detriment of businesses and consumers.

FPA Section 219(a) authorized the Commission to grant incentive-based rate treatments “for the purpose of benefitting consumers.” In its 2012 Policy Statement on Incentives, the Commission has rightly emphasized risk-reducing incentives, and limited the circumstances when it would award equity incentives. Given the significant interest in investing in low risk, nearly assured recovery, transmission assets at the Commission’s “base” equity return that is intended to reflect the cost of attracting capital, there is no reason to expand the availability of equity return heighteners beyond those in FERC’s 2012 Policy Statement.

C. Joint transmission ownership arrangements should be more aggressively encouraged

Although FERC’s 2012 Incentive Policy Statement rightly recognizes the role of joint ownership arrangements as a way of demonstrating that an applicant for incentives is using appropriate mechanisms to minimize risks, it has not yielded expanded opportunities for transmission investment by load-serving entities ready, willing, and able to make such investments. Given the Commission-recognized benefits of joint ownership arrangements (including minimizing state siting and permitting risk, making it more
likely that the project will be built), more should be done to make opportunities for all
load-serving entities in the footprint to invest in their load-ratio share of the transmission
grid a reality. Doing so would achieve Section 217's purposes by enabling load-serving
entities to directly participate in ensuring that their reasonable needs are satisfied, and
would allow them to offset the increasing cost of transmission, benefiting consumers and
businesses.

Those seeking transmission rate incentives, particularly incentive equity returns,
to induce their investment should not be permitted to turn away load-serving entities in
the footprint seeking to make their load-ratio investment in the grid. Instead, a showing
that the applicant has offered such investment opportunities on reasonable terms should
be a prerequisite for incentives.

In addition, the Order 1000 transmission planning process can be a more effective
vehicle for inclusive transmission investments. Non-incumbent transmission developers,
especially those (like GridLiance) that accommodate participation by small load-serving
entities, should have a fair opportunity to compete to develop needed new transmission.
Unfortunately, despite Order 1000's efforts to promote a competitive transmission
development process and vigorous competition for those projects that have been open to
competition, positive results have been limited. FERC Staff's own analysis shows that in
2016, no proposals submitted by nonincumbent transmission developers were selected by
any of the transmission planning regions that had competitive proposal windows—a
strong indication that the Commission's effort to foster more efficient and cost-effective
transmission development through competition is significantly flawed.\textsuperscript{17} Congress should encourage the Commission to revisit and reinvigorate the Order 1000 competitive transmission development process in a manner that will promote joint transmission ownership, as well as use competitive discipline to curb rising transmission cost.

Once again, I would like to thank the Committee for this opportunity and look forward to your questions.

May 10, 2018

Mr. OLSON. Thank you, Mr. Twitty.

Our final witness is Mr. Rob Gramlich.

Mr. GRAMLICH. That is right.

Mr. OLSON. Rob is the President of Grid Strategies LLC.

You have 5 minutes for an opening statement, sir.

**STATEMENT OF ROB GRAMLICH**

Mr. GRAMLICH. Thank you very much, Vice Chairman Olson, Ranking Member Rush, members of the subcommittee. I appreciate the opportunity to be here today to talk about the important issue of the state of transmission.

There is no infrastructure more important than transmission, which is essential to the reliable and affordable electricity service we depend on for almost every modern commercial and individual activity.

Since this subcommittee was involved in passing the Energy Policy Act of 2005, the industry has succeeded in building a lot of transmission. Transmission benefits have exceeded the cost by factors of 2 to 3.5 in the major investments in the central region you have heard about in MISO and the Southwest Power Pool.

Transmission investment has enabled over $100 billion of generation investment in rural communities. Transmission investment is needed for both a distributed future and a large utility-scale generation future, either one or both.

We have learned a lot about what works. Regional planning and cost allocation in particular have worked well. We should build on that success. In my written testimony, I provide nine ideas for expanding transmission and improving its performance.

However, none of these ideas matter if there is no leadership at the Department of Energy or FERC. I think we are waiting for that leadership. I fear the agencies are too distracted by misguided proposals to provide life extensions to old power plants. We are all wasting our time comparing different dictionary definitions of reliability and resilience when we should be updating policies for transmission. If “resilience” is a code word for propping up uneconomic plants, that effort needs to sink on its own poor merits, as my former boss, FERC Chairman and Texas PUC Chairman Pat Woods, said recently.

Turning to transmission. To improve transmission, most of my recommendations are for FERC, but I have some for DOE and Congress as well. It doesn't matter if it is under the heading of Order 1000, 890, 2000, or an entirely new vision they could roll out called Order 2020. We need to update transmission policy to create the grid we know we will need in the future.

I recommend that FERC and Congress preserve and build upon the twin policies I mentioned of broad regional planning and beneficiary-pays cost allocation. That is what worked in Texas, that is what worked in SPP, that is what worked in MISO. That is what Dr. Krapels described should be done in the Northeast.

Number one, FERC should align transmission owner incentives for advanced transmission technologies. I didn't say more incentives. I am not asking for a subsidiary. I said align the incentives so that transmission owners have an incentive to deploy cost-effective technologies.
Number two, FERC should incorporate advanced transmission technologies into transmission planning. I don't like to call it nonwires alternatives. I think they are just other transmission options. They should all be considered, along with new lines and other assets.

Number three, FERC should fix interregional planning and cost allocation. Clearly, no improvements have been made since Order 1000's attempt to improve that.

Number four, Congress, the Department of Energy, and FERC should all improve Federal backstop siting. I think it is important for the future grid that we need, and we should make sure it works and is used where appropriate.

Number five, FERC should require proactive planning that captures all of the values of transmission. Too often it gets compartmentalized and not all of the benefits are included.

Number six, the administration should improve Federal coordination and transmission permitting on Federal lands.

Number seven, the Department of Energy should harness the authority and capabilities of power marketing administrations. They can be involved in transmission, they can utilize Section 1222 of the Energy Policy Act of 2005, and help in other ways.

Number eight, the administration should couple the Department of Energy's planning and support for planning and corridor designation with the Department of Interior's efforts to identify renewable energy zones and transmission corridors.

Finally, Congress should consider public financing to right-size transmission. Too often we underbuild for the resources that we know will be there when our children, their children, and their children's children will benefit from it.

Those resources are there. We know they will be there even in Texas where we built a lot of transmission. We have essentially used up that capacity. And looking back, we would have done better to build it the right size.

I will stop there and look forward to your questions. Thank you.

[The prepared statement of Mr. Gramlich follows:]
Thank you, Chairman Upton, Ranking Member Rush, and Members of the Subcommittee, for inviting me to testify on the state of US transmission infrastructure. Since modern society requires affordable, clean, and reliable electricity for just about every activity, there is no infrastructure more important than the interstate electric network. I serve as Executive Director of the WATT Coalition (Working for Advanced Transmission Technologies), on the board of the Americans for a Clean Energy Grid coalition, and have a consulting practice called Grid Strategies LLC that provides analysis and regulatory policy support for clean energy integration and delivery.

Transmission delivery capability has improved markedly since this Subcommittee helped pass the Energy Policy Act of 2005. While providing a source of optimism, that progress still puts the grid nowhere near where it needs to be given the age of existing transmission assets, the need to connect new generation and consumption sources, the opportunity to develop rural economies by accessing remote resources, and the many reliability and economic benefits that would accrue to electricity customers with an expanded and more dynamic bulk power network.

I recommend that FERC and Congress preserve and build upon the major twin policies that succeeded in increasing needed transmission investment over the last decade:

1) broad regional planning, and
2) beneficiary pays cost allocation.

I recommend that FERC and Congress remedy the lack of progress in inter-regional transmission and innovation through:

1) Fixing inter-regional planning and cost allocation;
2) Promoting the adoption of technology and innovations to deliver more over the existing grid;
3) Implementing limited federal support permitting of inter-state transmission lines.
I. Great progress has been made

Around the time of the Energy Policy Act of 2005 ("EPAct"), annual transmission investment had fallen to around $4 billion per year. Today annual transmission investment is close to five times that amount, around $20 billion. This investment has resulted in significant new transmission highways delivering very low-cost wind onto the high voltage network. The image below shows new transmission lines in black connecting the highest quality wind resource areas (shown in red and purple), particularly in the middle of the country with demand centers.

Figure 1: Recent High-Voltage Transmission and Wind Resources

A. Benefits to customers of recent transmission investment

These investments have benefitted customers. The Southwest Power Pool (SPP), the grid operator for Kansas, Oklahoma, Nebraska, and parts of neighboring states, evaluated the many categories of benefits provided by its recent transmission upgrades. SPP found that the transmission upgrades it installed between 2012 and 2014 create nearly $12 billion in net present value benefits for consumers over the next 40 years, or around $800 for each person currently served by SPP, or $2,400 per each metered customer. The $16.6 billion in gross savings is higher than SPP's transmission planning models had initially estimated, and 3.5 times greater than the cost of the transmission upgrades. As shown in the following chart from SPP's report, these upgrades are already paying for themselves, and the benefits only grow over time while the costs decline.

SPP: Benefits (left bar) exceed cost (orange bar) of transmission upgrades

https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

2
SPP’s report shows the wide range of benefits provided by transmission: it reduces the cost of producing electricity, reduces the need for power plants by improving power system efficiency, increases electricity market competition, improves electric reliability, makes the power system more resilient to unexpected events, reduces environmental impacts, and creates jobs and economic development.

The Midwest grid operator, also testifying today, conducted analysis of grid upgrades that are currently underway, and found $12 billion to $53 billion in net benefits, or between $250 and $1,000 for each person currently served by MISO. The benefits were 2.2 to 3.4 times greater than the cost of transmission, an increase from the 1.8 to 3.0 benefit-to-cost ratio that was initially calculated when the transmission was planned in 2011. MISO found that congestion and fuel cost savings associated with providing consumers with access to lower-cost energy sources accounted for between $20 billion and $71 billion of the gross benefits, a large share of the total. The New England grid operator similarly saw a large reduction in the congestion-related costs paid by consumers after it made significant investments in transmission upgrades. Specifically, congestion costs fell from in excess of $600 million per year in 2005 and 2006 to under $100 million annually.

B. Ingredients for success: planning and cost allocation

Credit for success in transmission investment in RTO and ISO regions goes to the twin policies of transmission planning and cost allocation. Each of these RTO/ISO regions use a form of wide regional transmission planning (over wider regions than planning was done prior to ISO and RTO formation), and broad beneficiary-pays cost allocation. Texas, as a single state outside of FERC jurisdiction, spreads transmission costs over all users. In FERC-jurisdictional ISOs and RTOs, the formula in each case is a form of beneficiary pays where costs are recovered in the ISO or RTO tariff. Providing a mechanism for planning and cost allocation was a major reason for ISO and RTO formation and the creation of regional planning processes and tariffs has paid off.

Broad regional planning and cost allocation are the core elements of FERC Order No. 1000 and should be preserved and expanded, as discussed below.

II. We have a long way to go

Costly congestion remains on the system. Nationally, consumers are paying approximately $4 billion per year in the areas with Regional Transmission Organizations and Independent System Operators as shown in Table 1 below. Since those cover approximately two-thirds of the country, one could extrapolate to the rest of the country and infer that total is approximately $6 billion per year.

<table>
<thead>
<tr>
<th>Region</th>
<th>2016 congestion cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAISO</td>
<td>142</td>
</tr>
<tr>
<td>ERCOT</td>
<td>497</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>39</td>
</tr>
</tbody>
</table>

Future projections of the US electric system find major opportunities for an expanded grid. A large consortium of grid operators, DOE national laboratories, and other researchers are currently developing an optimized national transmission expansion through the ongoing Interconnection Seams Study. The image below shows one grid configuration being considered where a major high voltage DC overlay is added to the current network.

**National Laboratory Seams Study Transmission Scenario**

As indicated in the following table from a presentation of the study’s preliminary results, these transmission investments yield benefits that are many times larger than their cost. The blue cells show the cost of each transmission addition, while the orange cells tally the benefits of that transmission. The bottom yellow cell calculates the benefit-to-cost ratio for each design, which range from 2.5:1 to 3.3:1 depending on the design over a 15-year period. Benefits continue for the estimated 40 year lifetime of the transmission lines. Even without accounting for the cost of carbon emissions, the transmission investments were found to have a benefit-to-cost ratio of 2:1 or 3:1 over 15 years, depending on the design.

---

**Table:**

<table>
<thead>
<tr>
<th>Region</th>
<th>Cost</th>
<th>Benefits</th>
<th>Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>MISO</td>
<td>1,400</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NYISO</td>
<td>529</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PJM</td>
<td>1,024</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SPP</td>
<td>280</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,911</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

Another study published in the journal *Nature Climate Change* examines the benefits of building an even larger nationwide transmission network that could save consumers as much as $47 billion annually, a roughly 10 percent reduction in electric bills.\(^7\)

Other studies have looked at regional transmission investments. Last year, the National Renewable Energy Laboratory (NREL) released detailed analysis of several proposed transmission lines in the Western U.S., shown below. It found that these lines would cost $10 billion but save $2.3 billion per year,\(^8\) which indicates the lines themselves would have a payback period of around 4 years.

\(^7\) [http://www.nature.com/nclimate/journal/vaop/ncurrent/full/nclimate2921.html](http://www.nature.com/nclimate/journal/vaop/ncurrent/full/nclimate2921.html)

---

### Table: Economic Analysis

<table>
<thead>
<tr>
<th>Component</th>
<th>Design 1</th>
<th>Design 2</th>
<th>Delta</th>
<th>Design 3</th>
<th>Delta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line Investment Cost</td>
<td>$61,200</td>
<td>$73,800</td>
<td>$12,600</td>
<td>$86,800</td>
<td>$23,400</td>
</tr>
<tr>
<td>Generation Investment Cost</td>
<td>$70,330</td>
<td>$90,990</td>
<td>$20,660</td>
<td>$89,510</td>
<td>$19,180</td>
</tr>
<tr>
<td>Fuel Cost</td>
<td>$75,820</td>
<td>$78,980</td>
<td>$13,160</td>
<td>$82,140</td>
<td>$14,320</td>
</tr>
<tr>
<td>Total O&amp;M Cost</td>
<td>$45,650</td>
<td>$80,720</td>
<td>$35,070</td>
<td>$64,270</td>
<td>$19,720</td>
</tr>
<tr>
<td>Total Grid Cost</td>
<td>$64,570</td>
<td>$85,950</td>
<td>$21,380</td>
<td>$74,890</td>
<td>$10,320</td>
</tr>
<tr>
<td>Capital Cost</td>
<td>$77,470</td>
<td>$112,620</td>
<td>$35,150</td>
<td>$90,970</td>
<td>$13,500</td>
</tr>
<tr>
<td>Regulation Up Cost</td>
<td>$23,320</td>
<td>$31,630</td>
<td>$8,310</td>
<td>$30,450</td>
<td>$7,120</td>
</tr>
<tr>
<td>Regulation-Down Cost</td>
<td>$4,980</td>
<td>$6,200</td>
<td>$1,220</td>
<td>$5,920</td>
<td>$1,940</td>
</tr>
<tr>
<td>Capacity Cost</td>
<td>$26,310</td>
<td>$37,830</td>
<td>$11,520</td>
<td>$36,370</td>
<td>$9,050</td>
</tr>
<tr>
<td>Total Non-Op Cost (Billion)</td>
<td>2.114</td>
<td>2.413</td>
<td>$0.30</td>
<td>2.646</td>
<td>$0.53</td>
</tr>
</tbody>
</table>

### Table: Capacity GW

<table>
<thead>
<tr>
<th>Component</th>
<th>Design 1</th>
<th>Design 2</th>
<th>Delta</th>
<th>Design 3</th>
<th>Delta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total gas (MW)</td>
<td>600/180/370</td>
<td>600/180/370</td>
<td>0/0/0</td>
<td>600/180/370</td>
<td>0/0/0</td>
</tr>
<tr>
<td>Total DC (MW)</td>
<td>260</td>
<td>260</td>
<td>0</td>
<td>260</td>
<td>0</td>
</tr>
<tr>
<td>Total DC+AC (MW)</td>
<td>520</td>
<td>520</td>
<td>0</td>
<td>520</td>
<td>0</td>
</tr>
<tr>
<td>Total gas (GW)</td>
<td>0.23</td>
<td>0.23</td>
<td>0</td>
<td>0.23</td>
<td>0</td>
</tr>
<tr>
<td>Total AC (% of total)</td>
<td>25.6</td>
<td>25.6</td>
<td>0</td>
<td>25.6</td>
<td>0</td>
</tr>
</tbody>
</table>

### Diagram: Average Wind Penetration (%)
In another regional study, Charles River Associates examined the potential for a high-voltage transmission overlay in SPP. It concluded that the investment would provide economic benefits of around $2 billion per year for the region, more than four times the $400-500 million annual cost of the transmission investment. Of these benefits, $900 million would be in the form of direct consumer savings on their electric bills, with $100 million of these savings coming from the significantly higher efficiency of high-voltage transmission. The remainder would stem from reduced congestion on the grid allowing customers to obtain access to cheaper power.

Synapse Energy Economics also analyzed the net benefits of a large transmission upgrade in the MISO footprint. This analysis found significant net savings for consumers from this transmission expansion, between $3 billion and $9.4 billion in net savings per year, or $63-200 in annual benefits per household in the region.

Transmission investment is needed at a minimum to replace old transmission assets. Like most infrastructure, this equipment will likely see a higher failure rate as it nears the end of its life, putting reliability at risk. Nationally, most of our transmission infrastructure was built between 1960 and 1980; according to one estimate, just replacing that infrastructure alone will cost around $8-14 billion per year over the next 25 years. A similar estimate is that the grid will need $57 billion over the next five years alone. Grid operators confirm that their transmission infrastructure is reaching the end of its life and must be replaced. As America undertakes that investment, it should also account for future needs and ensure that the size of transmission investment is optimized to realize the benefits outlined in this section.

The vision of a high-capacity transmission network is being realized in other countries like China, India, and Europe. China is building a network of extra-high-voltage AC and DC transmission lines. The 800kV DC links have a capacity of around 8,000 MW, and China recently awarded a contract to build a 12,000 MW 1,100 kV DC line, which will be a world record. For comparison, the DC Pacific Intertie that ties the U.S. Pacific Northwest to Southern California operates at 500kV and can carry up to 3,800 MW.

---

10 http://files.brattle.com/system/publications/pdfs/000/005/190/original/investment_trends_and_fundamentals_in_us_transmission_and_electricity_infrastructure.pdf#page=7
III. We should start by using the existing grid more efficiently

As with most other forms of infrastructure, great advances in monitoring and control systems can improve electricity reliability and efficiency. Customers who are required to pay for transmission understandably want to assurance that the existing wires are being used to their maximum capacity. FERC and state regulators should first make sure that efficient, low cost solutions are deployed.

There are a set of cost-effective technologies that can increase the flexibility, reliability and utilization of the existing grid. When Congress passed the Energy Policy Act of 2005 encouraging FERC to deploy advanced technologies, these network optimization options were not sufficiently developed for wide commercialization. They are now.

A. Technology options

Leading technology options which can be used separately or together include:

Dynamic Line Ratings

The capacity of many transmission lines is limited by the temperature at which it can safely operate. Ambient temperature, sunlight, wind speed and direction, sunlight, and other weather factors that cool the lines can significantly increase their capacity. Dynamic Line Ratings (DLR) increase capacity on existing transmission lines by calculating capacity ratings based on actual monitored conditions rather than fixed worst-case assumptions. With DLR, even relatively low wind speeds can significantly increase the rating of a line by cooling it, reducing the impact of curtailments and transmission congestion on customers and producers of wind energy. The benefits are particularly large for wind energy because
high wind speeds cooling the lines also increase the amount of wind electricity being generated and transmitted over the line. Estimates of increased capacity have been 40 percent, 30 to 70 percent, and 30 to 44 percent on three different tests. DLR systems also provide forecasted ratings up to 48 hours ahead. For the line shown in the chart below, the increase in capacity tends to be highest when congestion is highest. DLR systems also improve reliability by alerting operators to conditions such as line sag clearance violations if conditions are hotter and actual capacity on the line is lower than the fixed engineering estimates.

DLR supports grid resilience by offering condition-based line capabilities when contingencies occur. For example, when a line trips, the increased flow on other lines may be tolerable based on actual

\[\text{Modeled Capacity in Kansas Transmission Line}\]

\[
\begin{array}{c}
\text{Percent of time at or above given capacity} \\
\text{Modeled Capacity in Kansas Transmission Line19}
\end{array}
\]


conditions even if the static, worst case assumption-based setting would lead to a protective action to trip the line. Relays could be programmed to take actual conditions into account.  

DLR technology can be rapidly deployed as it is minimally invasive and usually does not require de-energization of transmission lines and the resulting complex outage coordination required. A variety of systems have been demonstrated, including directly measuring line temperature and other properties, and in a non-contact form, measuring line Electromagnetic Fields (EMF).  

DLR has been deployed on a large scale in Europe. Belgium’s Transmission System Operator Elia deployed systems on all of its critical overhead lines to France and the Netherlands, helping it maximize import capability after the retirement of three large power stations.  

Advanced Power Flow Control

Power Flow Control refers to a set of technologies that effectively push or pull power away from overloaded lines and onto underutilized corridors within the existing transmission network. Advanced power flow control provides this same function with advanced features such as the ability to quickly deploy, easily scale to meet the size of the need, or redeploy to new parts of the grid when no longer needed in the current location.

Topology Optimization

Transmission topology optimization is a software technology that automatically identifies reconfigurations of the grid to route power flow around congested or overloaded transmission elements, taking advantage of the meshed nature of the power grid. The reconfigurations are implemented through switching on/off existing high voltage circuit breakers. By more evenly distributing flow over the network, topology optimization increases the transfer capacity of the grid. Acting as a grid configuration “search engine,” topology optimization can reduce congestion by up to 50 percent and improve response to contingencies, supporting reliability and resilience. It can reduce renewable

---


energy curtailment by up to 40 percent.\textsuperscript{24} Optimization methods are much cheaper than hardware options such as phase angle regulators (PARs).\textsuperscript{25}

Storage

Battery and other forms of storage can alleviate transmission congestion through charging and discharging at either side of a constraint. While storage can only move power over time and not space, and therefore is not a total replacement for all transmission needs, it can shift flow to times when congestion is less pronounced. It is very often the case that congestion changes over the timeframe that storage sources can store energy. Helping to alleviate transmission congestion or defer essential transmission upgrades is one of the many uses of storage technologies.\textsuperscript{26}

B. Policies to Promote Advanced Transmission Technology Deployment

Deployment of the technologies described above requires some action on an important piece of unfinished implementation business in The Energy Policy Act of 2005. The Act states that “In carrying out the Federal Power Act (16 U.S.C. 791a et seq.) and the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.), the Commission shall encourage, as appropriate, the deployment of advanced transmission technologies.”\textsuperscript{27} The Act provided for incentives to “encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities.” (italics added) FERC implementation of this Act focused on grid expansion and has yet to address the operations part of the job.

The Commission, to its credit, has recognized this gap. After five years of experience with Order No. 679 which implemented this Act the Commission undertook a review. In a Notice of Inquiry the Commission observed “To date, the vast majority of applications for transmission incentives filed with the Commission have focused on the enlargement of facilities, including construction of new transmission facilities. Few applications have focused on the improvement, maintenance, and operations of transmission facilities or on increasing their capacity or efficiency... For example, this could include software improvements that enhance scheduling and dispatch or investment in tools to enhance self-healing grid capabilities or...”


\textsuperscript{26} http://energystorage.org/energy-storage/technology-applications/transmission-support-and-avoidance-congestion-charges

\textsuperscript{27} EPAct 2005, Section 1223, Title 42 U.S. Code § 16422, Chapter 149, Subchapter XII, Part A (2005).
improved situational awareness." The inquiry led to a policy statement that clarified FERC's incentive policy for grid expansion related issues, but not grid utilization. It acknowledged once again the issue: "Investments in the following types of transmission projects may face the types of risks and challenges that may warrant an incentive ROE based on the project's risks and challenges that are not either already accounted for in the applicant's base ROE or could be addressed through risk-reducing incentives: ...3. projects that apply new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities...Examples of projects that meet this description include those that create additional incremental capacity without significant construction (e.g., through the use of dynamic line rating), that allow for more efficient balancing of variable energy resources, and/or that provide increased grid stability. In addition, the Commission is concerned that its current practice of granting incentive ROEs and risk-reducing incentives may not be effectively encouraging the deployment of new technologies or the employment of practices that provide demonstrated benefits to consumers. Accordingly, the Commission remains open to alternative incentive proposals aimed at supporting projects that achieve these ends."

The Commission has attempted to include transmission utilization technologies in its planning requirements. In the Commission's major reform of Open Access Transmission Tariffs in Order No. 890 in 2007, it stated:

"Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process. ... When evaluating the merits of such alternative transmission solutions, public utility transmission providers in the transmission planning region also must consider proposed ... alternatives on a comparable basis. If the public utility transmission providers in the transmission planning region, in consultation with stakeholders, determine that an alternative transmission solution is more efficient or cost-effective than transmission facilities in one or more local transmission plans, then the transmission facilities associated with that more efficient or cost-effective transmission solution can be selected in the regional transmission plan for purposes of cost allocation." Later in the Commission's major reform of regional transmission planning in Order No. 1000, it reinforced this Order No. 890 requirement:

"However, we note that in Order Nos. 890 and 890-A, as well as in orders addressing related compliance filings, we have provided guidance regarding the requirements of the Order No. 890 comparability transmission planning principle. Specifically, public utility transmission providers are required to identify how they will evaluate and select from competing

---

solutions and resources such that all types of resources are considered on a comparable basis.\footnote{Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 156 FERC ¶ 61,051, Par 155. https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf}

Despite these attempts to address advanced transmission technology in its incentive and planning policies, the job has not been accomplished. Now that technologies have matured to a point that much more market potential exists, it is a good time for the Commission to rectify this gap and review its planning and incentives policies. This does not necessarily mean there is a need for more incentives (which are appropriately viewed with skepticism by customers), but rather better alignment of incentives. In transmission as with other regulated industries, the challenge of the regulator is to structure incentives and rules to lead regulated entities towards efficient outcomes. That alignment is not currently present on transmission operations. It would benefit customers to allow for technology improvements where the savings are shared between customers and shareholders. The Commission has ample authority to pursue such reforms.

IV. Grid expansion policy improvements

Along with improving grid operations, policy makers can build on the last decade’s success in expanding the grid to further capture the benefits of a more national integrated grid through the following actions:

A. Fix inter-regional planning and cost allocation

Although FERC Order No. 1000 required neighboring transmission planning regions to coordinate planning, it has resulted in very little expansion of inter-regional grid capacity. Some of the problems include differences between regions in benefits metrics, criteria, and cost allocation policies. Since each region’s approach is different, there is a “triple hurdle” where a project must clear three tests, one for each region, and one combined test.

FERC can remedy the “triple hurdle” by harmonizing the different methods and criteria between each neighboring RTO. The Commission could also provide an affirmative obligation to identify and jointly evaluate alternatives proposed by stakeholders, remove exclusions on projects of certain voltage levels or project sizes, and require consideration of public policy requirements as part of the assumptions that go into planning models. FERC has sufficient existing authority to take this action.

B. Improve federal backstop permitting

After the 2003 blackout where transmission infrastructure constraints were among the many contributing factors, this Subcommittee and Congress included a limited backstop permitting role for the federal government in Section 1221 of EPAct 2005. This authority has never been used. A couple of court decisions have raised uncertainty about how it can be applied. The program will likely be needed if we are going to create the robust inter-regional delivery capacity we need. Congress, DOE, and FERC could each play a role to clarify this authority and establish workable processes so that it can be used where needed. I recommend that for specific extra high voltage (e.g., 500kV and up), long distance lines that provide broad multi-state reliability benefits and long-term consumer benefits, where state approval has been withheld after thorough consultation, DOE and FERC should be encouraged to be
willing to use the current authority. The current authority is still a meaningful amount. It is also important for Congress to clarify the authority in response to the court decisions.

C. Require pro-active planning that captures all values of transmission

Transmission planning, both within and across regions, tends to be reactive and fails to capture the range of benefits that new lines create. A study prepared by five universities for the Eastern Interconnection Planning Collaborative, National Association of Regulatory Utility Commissioners, and the Department of Energy found that traditional planning approaches are not adequate to achieve least-cost outcomes in light of the modern market and challenges in today's electric transmission system, including plant retirements, renewable integration, and changing environmental regulations. The study found that anticipatory transmission planning would, as compared to the outcome of traditional reactive planning, reduce total generation costs by $150 billion, increase interregional transmission investments by $60 billion, and achieve an overall system-wide savings of $90 billion.

The WIRES group has provided a series of helpful white papers that provide guidance on how efficient planning can be performed. The basic formula is simple: 1) transmission should be pro-active, to build the transmission expected to be needed in the future with different resources and loads; and 2) transmission planning should consider all of the expected benefits including reliability and efficiency, with public policies taken into account. Failure of planners to either pro-active or consider all the benefits leads to underbuilding of transmission.

One benefit of transmission—connecting new generators and resource areas—is particularly disconnected from the rest of the transmission planning process. In its recent order on transmission interconnection queue reform, FERC provided many improvements to the process. But it did integrate planning and interconnection, and it did not require consideration of advanced transmission technologies as alternatives. Those issues remain to be addressed.

Transmission planning can also be more efficient if done probabilistically (considering many future scenarios) rather than deterministically (with one or a small number of expected futures). Probabilistic methods that quantitatively account for uncertainty in the transmission planning process result in a larger and more optimal transmission build, saving consumers tens of billions of dollars relative to deterministic methods that fail to account for the value of transmission in providing flexibility and hedging against uncertainty. Moreover, the probabilistic method saved hundreds of billions of dollars relative to some deterministic planning methods that greatly underbuilt transmission.

FERC can lead these changes, following three decades of Commission work to improve regional transmission planning: “Regional Transmission Groups” in the late 1990s, Independent System Operators and Regional Transmission Organizations beginning in the late 1990s, Order No. 2000 in 1999, Order No. 890 in 2007, and Order No. 1000 in 2013.

---

31 See Eastern Interconnection States’ Planning Council, Co-optimization of Transmission and Other Supply Resources (September 2013), available at http://pubs.naruc.org/pub/36083A4-2354-D714-51D6-4E55431F23AA.
There is a role for the Department of Energy as well. Effective regional planning requires active engagement of stakeholders, especially states. States and other stakeholders can better participate with support for modeling and process facilitation, which are both strong capabilities of DOE.

D. Improve federal agency coordination and transmission permitting

On February 2, 2016, DOE published a Notice of Proposed Rulemaking titled Coordination of Federal Authorizations for Electric Transmission Facilities, which proposes a simplified Integrated Inter-Agency Pre-application (iIP) Process for inter-jurisdictional engagement. The DOE should explain how the energy corridor designations mandated by Section 368 of the Energy Policy Act, which are under revision by the Bureau of Land Management (BLM) and the U.S. Forest Service (USFS), and the DOE’s IPP Process will be integrated with one another. These agencies should identify transmission routes and paths that align with future energy resource areas that are expected to be developed in the near future and prioritize permitting and agency coordination.

The administration can support infrastructure development with sound and strong implementation of the FAST/DRIVE Act. Subpart D of this Act includes the Federal Permitting Improvement Act that aims to improve the permitting process for major infrastructure projects, including transmission, costing $200 million or more. The law establishes a federal interagency council chaired by a Presidential appointee to develop permitting performance standards, set deadlines, and enable the public to track the progress of major federal permitting actions. However, the provisions terminate seven years after enactment and should be made permanent. Administrative improvements such as deadlines, a single point of contact, enforcement of timelines, and agency disagreement resolution are important activities that could speed up the decision-making process. National Environmental Policy Act (NEPA) review of clean energy transmission over federal lands should include the positive environmental benefits of the lines -- e.g., supporting zero carbon electricity -- when considering alternatives.

E. Harness the authority of the Power Marketing Administrations to build additional transmission

The Power Marketing Administrations (PMAs), including Bonneville Power Administration, Western Area Power Administration, Southwestern Power Administration and Southeastern Power Administration, under the authority of DOE, own tens of thousands of miles of existing high-voltage transmission lines and have transmission financing and development authority. This massive existing transmission infrastructure and strong related authority should be harnessed to accelerate U.S. transmission development for new energy sources.

PMAs should be encouraged to partner with private developers, which allows private parties and not taxpayers to fund infrastructure development, while utilizing PMA assets and tools. Section 1222 of the 2005 Energy Policy Act authorizes the Secretary of Energy, acting through WAPA or SWPA, to "design, develop, construct, operate, maintain, or own, or participate with other entities in designing, developing, constructing, operating, maintaining, or owning, an electric power transmission facility and related facilities" needed to upgrade existing transmission facilities owned by SWPA or WAPA or in connection with new facilities located in any state in which SWPA or WAPA operates. BPA has similar transmission development authority under the Federal Columbia River Transmission System Act. This authority has only been used once, and that action was recently terminated by mutual agreement of the parties.

F. Couple DOE federal transmission planning with the Department of the Interior’s development of federal renewable energy zones
Using authorities established by the Energy Policy Act of 2005, the administration should revise the energy corridor designations by prioritizing transmission that specifically links the DOI renewable energy zones to large population (load) centers throughout the western United States. As the DOI moves to streamline approval processes and identify lands targeted for renewable energy development, the BLM, USFS and DOE should leverage the work required by a landmark 2012 settlement agreement reached with a coalition of conservation organizations and a western Colorado county. The agreement requires changes to a Bush-era plan mandated by Section 368 of the Energy Policy Act of 2005 designating "energy corridors" in the West. As the DOI develops renewable energy zones, the BLM, the USFS and DOE should designate "renewable energy transmission" corridors to service those zones.

G. Consider Public Financing to "Right-Size" Transmission

Money is wasted when we build lines that are too small. Even in the best US example to date of pro-active transmission planning of Texas Competitive Renewable Energy Zones, many of those lines are now oversubscribed, and it is clear that it would have been better for customers to build the higher capacity option that was considered and rejected. There is solid and stable information on where resource areas exist so if we pro-actively build transmission to those areas, development will come and our children and their children will benefit from it. However there is often not private market interest in financing capacity that will be used years into the future. There is therefore a good economic policy argument for public financing to fund the "right-sizing," or a higher capacity version of a line that private parties are willing to partially fund. The co-funding by private parties provides an important check to ensure lines are valuable, and the public financing achieves the more efficient level. Public financing could take a variety of forms.

V. Conclusion

I appreciate the Subcommittee's interest in this important topic. I hope it can support both better grid utilization and grid expansion with some of the ideas provided.
Mr. Olson. Thank you, Mr. Gramlich.

And for the panel, we are having votes called within the next 10 to 15 minutes, floor votes. We will have to basically go into recess. But until then, we will try to get through as many member questions as possible. We have 5 minutes to ask questions.

Being the chairman, I am first.

And you all know that I am a Texan. And you all know that Texans love to brag about fellow Texans. We say they done something good. They said that in Haskell, Texas. Haskell is the home of our former Governor, our current Energy Secretary, Rick Perry. He did something good with what is called Competitive Renewable Energy Zones. He used those to fix a problem he had in Texas, a big problem.

We have a lot of wind power, but we have most power out west, rural Texas, where it is not needed. We need it in eastern Texas, central Texas, Houston, Dallas-Fort Worth, Austin, San Antonio.

But that CREZ initiative is part of why, as Dr. Krapels said, Texas leads the Nation in wind power. In fact, one day a couple years ago almost half our energy was provided by wind. Offshore Corpus Christi, Texas, that wind whips almost 300 days a year. We are making progress on that.

My question is for you, Mr. Gramlich. Can you talk about how the CREZ model worked and whether that is something we could do elsewhere?

Mr. Gramlich. Sure. And you are absolutely right, Congressman, the Texas CREZ model, as well as the ERCOT market structure overall, is a model for the country.

I think we would be doing a lot better in all of the FERC jurisdictional areas if we essentially had the ERCOT market model throughout the Northeast and the rest of the RTO-ISO areas, as well as its proactive transmission planning model that has access to all of that wind and gas resources and others out in western Texas and the Panhandle.

So essentially it is a simple formula of identifying where the generation resources are and proactively building to those resource. The alternative that is too often used in many other places is just to wait one by one for all the little projects to connect, and no one of them are going to build the transmission that are needed. So you need to proactively build and right-size the lines to the resource area.

Mr. Olson. Thank you.

And, Doctor, would you like to add anything, Dr. Krapels, you are the wind expert, about the CREZ model in Texas, how that worked out?

Mr. Krapels. I totally agree. And in the Northeast, we are looking at a wind resource offshore that could be 10,000 to 20,000 megawatts. Texas size, Mr. Chairman. Texas size.

Mr. Olson. That is very big.

Mr. Krapels. That is very big.

Mr. Olson. Huge.

Mr. Krapels. It represents a capital investment opportunity of $30 billion, $40 billion, big even by Texas standards. And yet our transmission policy in the Northeast is the opposite of that of
Texas. It is let the generators build and own the transmission, which seems almost insane to me.

We should do what Texas did. We should learn from Texas and build the transmission and plan the transmission first, and then let the generators compete like hell to get access to that transmission. That is what you did, and it works great.

Mr. OLSON. This is a great hearing so far.

The last question is for you again, Mr. Gramlich.

You recently wrote a white paper about new technologies that can optimize a transmission system in a much lower cost than building new transmission lines.

Can you briefly describe how that will work and compare that for the cost to the consumer, what the benefits are of your white paper, your plan?

Mr. GRAMLICH. Yes. Thank you, Congressman, for the question.

I formed a coalition called the WATT coalition, Working for Advanced Transmission Technology. And we put out a white paper where we were thinking, in part, about wholesale customers and thinking we do need more transmission, but we should also make sure that the existing grid is used as efficiently as possible.

And many of these new technologies actually weren’t really commercially available when the Energy Policy Act directed FERC to promote them back in 2005. And so there is an unfinished chapter in the implementation of Congress’ act, and that is on the operational side, the utilization of the existing wires. A whole lot was done on incentives for new transmission, but nothing was done on utilization.

And so, again, we are not asking for more incentives necessarily, just alignment of incentives and inclusion into the planning process.

Mr. OLSON. Thank you. I am running out of time here.

One question for you, Mr. Clark. I would be curious to know if you think regulators are doing a good job of keeping up with emerging technologies in the transmission or distribution space. Grade A, B, C, D, or something below that.

Mr. CLARK. I would say it is incomplete, if that is an answer.

Part of the challenge when we talk about regulators is you are looking at multiple jurisdictions of regulatory authority. So unlike the case of Texas where you have a wholesale regulator that is both the retail regulator and the wholesale regulator, for most of the rest of the country it is very difficult to bridge some of those divides. It is just the way the jurisdictional nature plays out.

FERC has wholesale authority and interstate transmission authority. But many of those other decisions, regarding resource adequacy, integrated resource planning, retail decisions, are made at the State level.

So it is tough to give an overall grade because of the natural jurisdictional divide that sometimes creates tension.

Mr. OLSON. Thank you. My time has expired.

It is now time for Mr. Rush, the ranking member of the subcommittee, to ask his 5 minutes of questions.

You are up, sir.

Mr. RUSH. I want to thank you, Mr. Chairman.
Mr. Gramlich, as I mentioned in my opening statement, we are moving into a new energy paradigm where advanced technologies, such as distributed energy, microgrids, and energy storage are increasingly being developed and coming online.

In your opinion, is Order 1000, as constructed, the best way to increase the deployment of these types of low-cost, clean energy resources?

Mr. GRAMLICH. Sure. Thank you for the question.

We are, indeed, moving toward that future of a more distributed network with many small, sometimes retail or State jurisdictional resources. I think the planning processes need to incorporate that.

I do not agree with those who say that means we are not going to need as much of the bulk power grid. In fact, resources are still often variable and remote, and we need to move the power around geographically as well as over time, which storage can do.

So we are going to need the big grid, so to speak, and we are also going to need much more coordination at the local level, which is really for State regulators to handle.

I think reliability and efficiency can improve, however, if we bring those distributed resources into the wholesale markets. There are going to be a lot more resources available. And if there are any shortfalls, for example, if we give them access to the wholesale markets, we will have a lot more reliability.

Mr. RUSH. Commissioner Clark, in your written testimony you stated that regions that are still served by vertically integrated utilities were already doing a fair amount of regional planning before Order 1000. And you maintain that Order 1000 actually replaced a collaborative, bottoms-up approach to transmission planning with more bureaucracy and a compliance checklist that may not necessarily result in additional transmission developments.

Briefly, what recommendations would you suggest that would help improve Order 1000 to better achieve the goals of better process planning, better cost allocation, and increased competition, including for non-incumbent transmission developers?

Mr. CLARK. Thank you for the question, Ranking Member Rush.

What I would do for those, especially those regions of the country where—which is still the majority of the States—where the States maintain vertically integrated utilities, I would argue that Order 1000 should be put on a pretty severe diet so that it is slimmed back in terms of trying to leverage those things that were working in the past. And you had indicated or referenced my testimony where I talk a little bit about this.

A lot of the compliance obligations with regard to things like competitive bidding and the process that each of these regions have to go through, through that, don’t fit very well in regions of the country that are still vertically integrated. And the reason is because utilities working with their State utility commissions had always done that sort of regional planning in the past. And MISO’s MVP suite of projects was referenced earlier as a good example of how that worked well.

Those types of projects we are not seeing coming forward anymore because now the name of the game is, well, we have to comply with Order 1000, and so it really just becomes a compliance ex-
exercise as opposed to the more organic process that happened, bottoms-up.

I think there are some different issues maybe in parts of the country that have restructured where you might have some natural tension between generation and transition as it relates to the marketplace. Even there I don’t think Order 1000 is working perfectly, as indicated by some of the examples that Dr. Izzo talked about.

But at the very least in those vertically integrated regions of the country, I think it could be slimmed down from a compliance standpoint. Maybe focus more on some of the good aspects of regional planning and collaboration, and maybe especially on interregional projects where there may not have been as much conversation going on as there was after Order 1000.

Mr. Rush. I yield back.

Mr. Olson. Thank you.

Mr. Long, 5 minutes for questions, sir.

Mr. Long. Thank you, Mr. Chairman, I appreciate you yielding to me.

Mr. Twitty, FERC Order No. 1000 that is being discussed was an effort to introduce market concepts to transmission development. But the scope of transmission completion to date has been severely limited during implementation, forcing American businesses and households to overspend for transmission projects.

Why is competition in this area so important?

Mr. Twitty. Well, I guess, Congressman—first, thank you for the question. We all believe that competition brings lower prices and better services. Whether that can happen in a commodity like transmission or, for that matter, other aspects of the electric business I think is still a question out for debate.

I think it is clear that we have to pay more attention to how transmission gets built, how its ownership share is divvied up, what the rates of return are that are provided to the people who are building it. And as I have suggested, there are lots of folks out there who don’t have the opportunity to participate in the ownership and in some cases even the planning for these projects.

I would suggest that if you really believe in competition, you really believe in having a grid that is right-sized, that everybody should be at the table. Whether we like Order 1000, the way it was written or the way it has been implemented, is a good question.

Mr. Long. You think it should be reexamined or——

Mr. Twitty. Well, yes. I don’t think there is any——

Mr. Long [continuing]. Repealed altogether?

Mr. Twitty. Yes. No. No. I think there are some good aspects to Order 1000, but I think it is not working the way it was intended. And if more people were part of the planning process, really a part of the planning process, really a part of the ownership structure, I think we would have a better outcome than we do today.

Mr. Long. According to your testimony, TAPS members in the Southwest Power Pool have seen an average annual rate increase of 17 percent for the last 5 years. That is annually.

A few weeks ago the FERC Commissioner sat at the same table where you folks are sitting today, and I told him that your former employer, City Utilities of Springfield, has studies that show that costs are substantially higher than other customers in the SPP.
What needs to be done, either by Congress or by FERC, to fix this trend of such high annual rate increases for my constituents in Springfield, where you live?

Mr. Twitty. Well, I mention in my testimony the rates of return that are offered by FERC today are pretty attractive. I think we would probably all agree that if we had our 401(k)s and our IRAs invested at those guaranteed rates of return we would be pretty happy.

So I think that needs to be addressed. As I suggested, I don't think there is any need for incentives on top of those guaranteed rate of return. So I think that is a big piece of it.

And the bottom line, as you mentioned, real customers paying real utility bills, like everybody in the room, pay these increases. And I would suggest that if it wasn't for abnormally low natural gas prices today that are masking lots of these problems, people would be at your doorsteps wanting solutions and they would want them pretty doggone quickly.

Mr. Long. Talking about transparency for a moment here. How would greater transparency in the planning process of transmission building impact the cost of those transmission services?

Mr. Twitty. Well, I guess I think that by transparency we are including a number of things. If we have more people at the table who are actually using the transmission grid, I think it is going to help the right size grid be built. I think it is going to impact the siting process. I think Commissioner Clark mentioned earlier, the siting process is probably the most critical aspect of building any of these kinds of projects.

I have been somebody that has knocked on people's doors asking for rights of way. And I can tell you that if you have mayors, you have elected members of boards of public utilities, for instance, that are part of that process, it is going to be a better process, it is going to get the right thing built, it is going to be done as quickly as possible, and all of that translates into lower costs.

Mr. Long. You mention in your testimony that grid resilience should not be justification for excessive investment. In our recent hearings, the concept of grid resilience has been described as a crucial characteristic our energy system needs.

Can you explain what you mean by that?

Mr. Twitty. Well, resilience seems to be the word of the day in our business. And there are so many risks, many of them presented through cyber threats, where we need to think about how the grid gets built and how the grid gets put back after an outage.

We would probably all agree pretty easily on what resilience is, particularly those people who have been, like Dr. Izzo, running a utility today.

But we shouldn't let it be the end-all be-all to build something that you can't cost justify. I used to say to our customers, look, we can guarantee your availability 100 percent of the time, but you couldn't afford the service. And then later the engineers would say, well, we probably really can't guarantee it 100 percent of the time.

So it needs not to be an effort to gold-plate the system in the name of “it will never go down.”

Mr. Long. OK. Thank you.

And it is good to see Chris here also today.
So I thank you all for being here. I yield back.

Mr. Olson. Thank you.

Mr. McNerney, 5 minutes for questions, sir.

Mr. McNerney. I thank the chair on this.

Mr. Krapels, your OceanGrid collector stations proposal for off-shore wind is pretty interesting. What types of proposals have you seen outside of the New York-New Jersey area, including the West Coast, where we have deep water out there?

Mr. Krapels. Thank you, Congressman.

I have seen and studied very carefully what the European countries have done. So both Germany and the Netherlands are the leaders in offshore wind deployment. And in both of those countries, the idea of an OceanGrid that is separately owned has been part of the policy for some time, and it works very, very well.

In California, I think it would be wise to look at the offshore in the same way that Texas looked at the upstate. It is a region with unlimited wind energy potential.

Floating storage wind turbine technology is evolving so quickly, I think it will be economic within the next few years. And thinking about this from a grid standpoint, build a grid that maximizes the benefits to consumers, would be the right way to go.

Mr. McNerney. Thank you.

Do we in Congress need to do something such as pushing the BLM’s offshore Federal land leasing to be structured so that neighboring wind farms can use the shared infrastructure?

Mr. Krapels. I think that would be extremely helpful. Right now each wind generator can build its own transmission line to shore, but once they do that, that place on shore is occupied by that generator for the rest of time. So thinking it a little bit more holistically would be very wise.

Mr. McNerney. Thank you.

Mr. Gramlich, you mentioned earlier that FERC does not need to grant more incentives, but to better align the incentives that we already have. What are your suggestions on how to go about doing that?

Mr. Gramlich. Thank you, Congressman.

There are examples from other countries that we are currently looking at and trying to work with a number of transmission owners on, as well as FERC staff and others. In the U.K., for example, when there is congestion, the transmission owner has an incentive to reduce that congestion, so thereby the savings are shared between customers and shareholders.

So that concept, I believe, could be applied here in the U.S. It is not an easy task to implement these forms of performance-based regulation, but I am optimistic that with a lot of the best minds from the transmission industry and regulators we can figure it out.

Mr. McNerney. Well, I am kind of interested in the D.C. overlay idea. What would be the next steps to get that to happen?

Mr. Gramlich. Number one, having people like you say that is an important thing to do. So thank you for that. Having FERC and the Department of Energy take interest.

I do think there is a very interesting study that I cited in my written testimony called the Seams Study that a number of na-
tional labs are working on that has been partially released, but not fully released.

That will be a great model. So when that comes out, I think facilitating a dialogue on how do we get that type of grid would be very worthwhile.

Mr. McNerney. Right. Well, you mentioned that there is a lack of private market interest in financing high capacity versions of the line, such as the Texas Competitive Renewable Energy Zones. Public financing to the right size may be appropriate. Can you discuss more about how such would be structured so that we don’t build excess capacity needlessly?

Mr. Gramlich. Thank you for that.

Yes, there is always a risk in regulated industries of overbuilding, and you need to think about that. But in this case we know where the resources are, right? The wind resources, the solar resources, geothermal, you name it. These are location-constrained resources that haven’t moved over generations and they are not going to move over generations.

I submit we shouldn’t be that worried about overbuilding to access those resource areas. Our great, great, great, great grandkids are going to benefit from whatever we do to build out that network.

Mr. McNerney. Interesting.

I am going to yield back in the interest of time, Mr. Chairman.

Mr. Olson. Thank you.

As a reminder, votes are about to be called. My intention is to alternate between Republican and Democrat until we have to go vote. We will recess for maybe a half an hour or 45 minutes and come back.

The next member to ask questions is Mr. Griffith from Virginia, 5 minutes.

Mr. Griffith. Thank you very much. And in the interest of time, I am going to send some questions afterwards, as we are allowed to do within the next 10 business days, and I will do that.

But I am going to ask one question live, Mr. Twitty, because I represent AEP country in southwest Virginia. And you mentioned that AEP’s zonal transmission rate has significantly increased, about 15 percent per year over the past 6 years.

I am wondering if you can explain that to the folks back home. And then answer the question: That is obviously a significant increase for customers in my area. Are there sufficient consumer protections in place to prevent unnecessary investments in the future?

So first explain why it is going up so much, if you can do it quickly, and then what do we need to protect folks.

Mr. Twitty. Well, I would answer it, Congressman, by saying, as I did to Congressman Long, it is too rich an investment for the people who own and build new transmission. It is too rich. We need to reduce returns on equity. We need to make sure we are not providing incentives on transmission investment for a run-of-the-mill, standard transmission line. That is certainly number one.

Number two, as I have said, I think we need more people at the table from the very beginning. Owners of transmission need to let those of us who need the transmission to get their generation to load to be at that table and to own a load ratio share.
These are the people who represent customers, real customers, and if they are at the table, I think they are going to do a lot of good work to make sure that there is no gold-plating, there is not any overbuilding, that we build exactly what it is we need to get generation to load.

It is a long process. It requires your influence on the FERC. It requires lots of people talking about these issues. It is easy to say we want somebody at the table.

If you are a transmission owner, you want to be a transmission owner and do exactly what you want. If there are other voices at that table, it gets a little bit messier. I think you get a better product if that is what happens.

Mr. GRIFFITH. Well, I appreciate that.

And with that, Mr. Chairman, I will yield back so somebody else can get a question in.

Mr. OLSON. Mr. Johnson, Mr. Long, Mr. Cramer, anybody want to question, yield, take the time?

Mr. JOHNSON. Thank you. Thank you, Mr. Chairman. I will make these quick.

Mr. Clark, one of the primary objectives of Order 1000 was to promote interregional transmission development. But there is broad consensus that Order 1000 failed to achieve that goal.

So in your opinion, how could this objective be achieved?

Mr. CLARK. Sure. I think part of it is, Congressman, and thank you for the question, part of it is, as I said, attempting to focus in on what you are actually trying to accomplish in the rule. The rule itself is expansive, it ran several hundred pages long, the compliance filings are probably thousands of pages on top of that.

And I think part of the reason that you get that result is the order tried to do a lot of things all at once. It was partly competition policy. It was partly an investment policy. It was partly a regional planning policy. It was partly a cost allocation policy. Some of it dealt intraregional things, some of it interregional things.

And when you push that much out in a rule and expect the regions to do something with it, you end up with, in my opinion, just a lot of bureaucracy and checking compliance boxes. That is why I say I think putting the order on a diet and trying to focus in on what you are really looking at doing probably would be the most helpful thing. Some of it may be reinforcing some of the planning conversations that happen, but without the more prescriptive elements of it.

And I think part of it might be focusing more on the issue of interregional projects as opposed to spending a lot of time within these regions having to vet through and try to manage the type of intraregional projects that were happening organically prior to the order itself.

Mr. JOHNSON. OK. What would be the advantages of greater interregional transmission?

Mr. CLARK. Because you have an interconnected grid, both in the West and in the Eastern Interconnect, there may be certain projects that serve a broad regional benefit that have benefit that accrues to many times over.
But if you are only looking within your region, you might not see the value of the benefit of those particular lines. Some of them could be reliability lines. Some could be market efficiency lines. But some sort of process to have a yardstick to compare the interregional type of projects might be valuable, and that may not have been captured in earlier FERC orders such as 890.

Mr. JOHNSON. All right. Thank you. I yield back.

Mr. OLSON. Thank you, Mr. Johnson.

Ms. Castor, 5 minutes, ma'am.

Ms. CASTOR. Thank you, Mr. Chairman.

Thank you to all the witnesses who are here today.

We recently in the Oversight and Investigations Subcommittee had an oversight hearing on the state of the grid in Puerto Rico. I want to thank the committee for continuing to focus on our neighbors in Puerto Rico.

Unfortunately, right after the Army Corps of Engineers and DOE testified that they thought they had things on track, they had a major outage again. So I would like to ask you all after to supplement the record with any recommendations moving forward there. Clearly, there is an issue on transmission and the need for microgrids and more resiliency there.

But as we work to modernize the grid everywhere and deal with the cost of the changing climate and building greater resiliency, we need to make sure we are taking advantage of nontransmission alternatives, such as microgrid, distributed energy resources, and energy storage.

Nontransmission alternatives not only have significant environmental benefits, but they can help prevent long-term area-wide blackouts after natural disasters, like we saw in Texas and Florida and Puerto Rico this summer.

We also need to be focusing on the needs of consumers and be a lot smarter. These nontransmission alternatives can be a great benefit to consumers. FERC Orders 890 and 1000 recognize the benefits of nontransmission alternatives, requiring regional transmission plans to consider whether nontransmission alternatives can more efficiently, cost-effectively, meet the needs of a region.

But despite all these benefits, these alternatives are not being utilized to the extent they should be, especially given how advanced the technologies have become.

So, Mr. Gramlich and Mr. Twitty, do you think that if there was a stronger FERC order that required more than just consideration of alternatives, we would see greater use? And what are the barriers to broader deployment and utilization?

Mr. GRAMLICH. I do. Thank you for the question.

For reliability and resilience, you can improve both by better monitoring and control of the infrastructure. It seems obvious. We do it with just about every other form of infrastructure with better monitoring and control systems and computing power. All through our economy we have these opportunities to monitor and control better, and that helps with reliability as well as efficiency.

So transmission is no different. The only problem is, it is a regulated industry, the incentives, as I said, are misaligned, and the planning requirements are not up-to-date with the new opportunities we have.
Ms. CASTOR. Mr. Twitty, short answer.

Mr. TWITTY. Congresswoman, thank you for the opportunity to respond to that. I would certainly agree with those comments. And I would suggest, as somebody who used to have responsibility for keeping lights on, at the end of the day that is the most important thing that all of us are after. Technology is a wonderful thing. It marches along. And yet implementing it in the real world, getting the right kind of investment at the right time, is always going to be critical, and making sure it works as it relates to the total grid.

It is one of the challenges today of intermittent resources. Wind and solar are wonderful, and we are all trying to figure out ways to harness them properly. But when the wind doesn't blow or the sun doesn't shine, it is a real challenge.

So you have to have a system designed that can take this intermittent resource, and in the case of microgrids turn over control of a part of your grid to others. And for people, again, like Dr. Izzo, who have responsibility for keeping lights on today, that is a pretty nervous thing, because if it doesn't work properly, if the technology isn't fully baked, lights go out and——

Ms. CASTOR. Highlights the importance of planning and investments. Thank you so much.

Mr. TWITTY. Exactly.

Mr. OLSON. Thank you. And seeing there are no further members wishing to ask questions, I would like to thank our witnesses again for being here today. Thank you. Thank you. Thank you. Much obliged.

Before we conclude, I would like to ask unanimous consent to submit the following documents for the record: a letter from GridLiance and a letter from WIRES. Without objection, so ordered.

[The information appears at the conclusion of the hearing.]

Mr. OLSON. And pursuant to committee rules, I remind members that they have 10 business days to submit additional questions for the record. I ask that the witnesses respond within 10 business days upon receipt of the questions.

Without objection, this subcommittee is adjourned.

[Whereupon, at 11:04 a.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

PREPARED STATEMENT OF HON. GREG WALDEN

Good morning and welcome to our witnesses. Today’s hearing on transmission infrastructure is another important topic in the Energy Subcommittee’s Powering America series. I want to thank our witnesses for participating and I look forward to hearing your perspectives on the state of our nation’s electric transmission infrastructure.

The United States’ electricity system is one of our nation’s more impressive engineering feats—with its interconnected network of power plants, poles, and wires that delivers uninterrupted electricity from producers to consumers. Transmission is an integral component of our electricity system. Often called the bulk-power system, transmission infrastructure enables the movement of electricity across states, regions, and the country as a whole. However, as time passes and transmission infrastructure ages, upgrades and replacement of existing infrastructure, as well as capital investments in new projects are necessary to ensure electricity is delivered in a reliable, efficient, and cost-effective manner.

Like many energy infrastructure projects, the construction of new transmission infrastructure can face difficulties, in part due to lengthy delays in permitting and
siting processes. Energy infrastructure projects such as natural gas pipelines and LNG facilities are subject to Federal Energy Regulatory Commission (FERC) permitting processes. On private lands, utilities, grid operators, or states make the decision on whether a new transmission line needs to be built and whether to upgrade existing transmission infrastructure. However, when it comes to siting and building transmission lines across Federal lands, the Department of Energy is the lead agency in coordinating all applicable Federal authorizations and related environmental reviews of electric transmission facilities, with some authorities delegated to FERC.

Consistent with the intent of the Administration’s recently announced MOU on implementing One Federal Decision, agencies must work together to provide a more predictable, transparent, and timely Federal review of infrastructure projects.

Through the Federal Power Act, Congress gave FERC the authority to regulate the sale and transmission of electricity in interstate commerce. Under this authority the FERC issued a series of rules to oversee and regulate the regional and interregional planning of transmission projects while at the same time encouraging greater competition between transmission developers. FERC’s most recent rule on transmission was in 2011, with Order 1000. Today’s hearing will explore these rules and the related challenges of transmission planning.

This Committee has discussed at length the importance of utilizing digital and information technologies for a more dynamic and innovative electricity system. Through previous Powering America hearings, we have focused on energy technologies located at the distribution level of the electric grid. However, new technologies have the potential to optimize the Nation’s electricity system at the bulk-power level.

Advanced grid technologies can modernize transmission infrastructure to ease congestion, allow for increases in demand, and provide greater security. These smart technologies include sensors for measuring system conditions, electric power equipment that regulates power flow, and computerized monitoring equipment that enable system operators to view the electric grid in real time and make necessary adjustments.

For example, these technologies can optimize the flow of electricity by automatically routing power around overloaded or congested lines—allowing for greater line capacity. High voltage direct current transmission lines can be a less expensive alternative and have less electrical losses compared to traditional alternating current lines in transmitting electricity over long distances. I look forward to hearing more from our witnesses today on how these advanced technologies have the potential to optimize transmission infrastructure at the bulk-power level.

The Nation’s transmission system is a vital component in the safe, reliable, and affordable delivery of electricity to consumers across the country. We must ensure that the electric grid works in ways that integrate new technologies within existing transmission infrastructure, and siting new infrastructure when needed. Thank you to our witnesses for joining us today and I look forward to your testimony.
May 9, 2018

The Honorable Fred Upton
Chairman, Subcommittee on Energy
House Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

The Honorable Bobby Rush
Ranking Member, Subcommittee on Energy
House Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

Dear Chairman Upton and Ranking Member Rush:

As one of the nation’s leading independent transmission developers, GridLiance applauds you for convening this week’s hearing on the state of electric transmission infrastructure, including the challenges associated with the planning and construction of new transmission lines, among other issues. A portfolio company of Blackstone Energy Partners, GridLiance’s differentiated business model is to work with electric cooperatives, municipal utilities, irrigation districts, and joint action agencies to help them plan for the future, invest with them or for them in electric transmission infrastructure, and implement strategies that meet their ownership, capital investment, and operational goals.

We appreciate the opportunity to provide the following views on the state of competition for new transmission construction introduced by the Federal Energy Regulatory Commission (FERC)’s landmark Order No. 1000, including aspects where implementation of FERC’s competitive transmission reforms can and should be improved.

As discussed in your staff’s memorandum of May 8, 2018, Order No. 1000 was an effort to introduce market concepts to transmission development. This effort is vital to ensuring that transmission investment decisions are as efficient as possible. Competitive forces have proven phenomenally successful in the electric generation sector, and if unleashed for electric transmission these forces can produce similarly impressive results. However, despite FERC’s best intentions, the scope of transmission competition to date has been severely limited during implementation, forcing American households and businesses to overspend for transmission projects. Although the Commission appropriately sought to optimize transmission additions through the planning requirements of Order No. 1000, the misguided desire to avoid a competitive mandate has led to an explosion of local transmission additions being constructed outside the regional planning processes in an effort by incumbents to avoid those very competitive forces that will produce more efficient infrastructure. Likewise, exploitation of exceptions to competition, whether included in Order No. 1000 initially or added through compliance filings, have further limited the value of ratepayers’ transmission expansion dollars. These exceptions have now limited competition to a tiny fraction of new transmission spend in most RTOs. For these reasons, the needed transmission system buildout occurring today is increasingly being sub-optimized at customers’ expense.

As the Subcommittee seeks to understand how it can ensure that the grid continues to respond to the rapidly changing conditions in the industry, we believe it is important to keep in mind three fundamental principles:

J. CALVIN CROWDER
President & CEO

GRIDLIANCE
1. It is critical for FERC to acknowledge that in expanding and modernizing the U.S. electric transmission network as necessary to meet resilience needs, competition can play a key role in delivering greater resilience benefits for fewer customer dollars. Competitive forces introduced by Order No. 1000 have proven to be an effective means of ensuring that the cost of new transmission construction required to meet ongoing grid resilience and reliability challenges are minimized for customers, without short-changing grid reliability. Where the competitive principles of Order No. 1000 have not been employed, ratepayers pay higher rates for transmission. For example:
   - Competition has led to proposals from companies containing cost caps that shift the cost risk for new transmission from ratepayers to project developers, more technically innovative solutions to adding transmission capacity, and reliability and construction quality comparable to incumbents.
   - Contrary to claims from the rule’s detractors, the costs to administer Order No. 1000 proposal windows are relatively low, especially compared to the documented savings for customers.

2. Adequate transmission solutions can create an electric grid that is more resilient to a wider variety of disruptive events. But simply rebuilding the electric grid of the last century through the guise of “asset management” or end of life criteria without analyzing whether that grid provides the resiliency resources for a new century, leaves grid planners and the Commission with transmission infrastructure that may not meet optimal or desired needs of consumers, and most importantly leaves ratepayers bearing the consequences of uneconomic decisions.

3. Getting the rules right on transmission development also requires that capitalized transmission owner “local” or “maintenance” projects that upgrade capacity, change voltage, or increase a line rating are developed and constructed through a FERC-approved open, coordinated, and transparent local or regional planning process. GridLiance applies the same standard to its planned capital maintenance program.

Thank you again for your consideration of these important topics. We look forward to continuing to work with the Subcommittee on these issues moving forward.

Sincerely yours,

Calvin Crowder
President and CEO, GridLiance
May 9, 2018
via Email (Energy.commerce@mail.house.gov)

Frederick S. Upton, Chairman
Bobby L. Rush, Ranking Member
Members of the Subcommittee
Subcommittee on Energy, Committee on Energy and Commerce
Rayburn House Office Building, Room 2125
Washington, DC 20515

Dear Chairman Upton, Ranking Member Rush, and Members of the Subcommittee:

Thank you for including these brief observations in the record of your hearing of May 10, 2018. Investment in transmission infrastructure is a subject of major national importance to which little attention is ordinarily paid and I therefore commend your efforts to elicit the best thinking on the subject.

Based on my years of experience in the energy area and my tenure leading the FERC, I can assert that no organization is more dedicated to promoting investment in the electric grid, modernizing its technology, or improving its regulation than is my client WIRES, a non-profit international trade association (www.wiresgroup.com). WIRES has produced for policy makers like yourselves and the industry a battery of studies on how transmission benefits North American economies and consumers, and how transmission, if made sufficiently robust, can ensure that we meet the challenges of an economy that is destined to be much more highly electrified in the coming decades. I am attaching for your review the comments we just filed at the FERC about why transmission investment is critical to the resilience of our electric system.

Let me share brief observations about the topics of your hearing. First, the level of transmission investment in recent years essentially made up for a quarter century of underinvestment, replaced aging and electro-mechanical facilities (some nearing a century old), and addressed short term reliability issues. We should not allow ourselves to rest on our laurels, however. Continued investment is not optional if we are to meet challenges of an electrifying economy, install modern digital technologies, deploy and serve more distributed resources, enhance regional and interregional energy markets, lower electricity prices for consumers (which are a declining share of the cost of living almost everywhere), and strengthen the grid against physical, cyber, and natural disruptions. The high-voltage grid must be storm-hardened and modernized for an environment that can be hostile to our electrified society – that’s where we urge the FERC to expend its resources and authority.

Second, no energy delivery system is more extensively planned, more regulated and overseen at more levels of government, or more resisted based on misconceptions about who these facilities benefit than is the transmission grid. The reasons for this are partly historical; we are building an integrated, regional and multi-state network under laws and a jurisdictional division of labor based on a completely outdated business model of local and state monopoly. Compared to the 3-4 years needed for natural gas pipelines for example, the planning, siting, permitting, and construction of transmission lines frequently require a decade or more. Uncoordinated environmental reviews are a small part of the problem, in my estimation.
The more important and extensive a project is, the more likely that affected states will fall into prolonged disagreement about who benefits and how the public interest should be served. It’s an old story with no solution on the horizon – at least not without your help.

Order No. 1000 has been part of FERC’s plan to move toward a more integrated, market-friendly bulk power environment. It has many critics. Some of the criticism that it has not yielded the transmission infrastructure it promised, commensurate with its administrative burdens, is entirely justified. I, for one, think its failure to produce more interregional projects to sustain broader markets is a major problem. However, the Commission appears to have taken a pass on opportunities to make the rules simpler, clearer, and more productive. Instead it has deferred to states and regions to develop their unique approaches, in effect perpetuating the patchwork of tariffs, rules, and procedures that critics complain about. But I hasten to add that Order No. 1000 instituted the regionalization of grid planning and allocation of costs to true beneficiaries that are, and should remain, the touchstones of grid regulation. It has generated many successes, and now we should move beyond it. Nevertheless, the public and industry would be well served if FERC took a fresh look at its long-term electricity market objectives and began down the road to major improvements to what is already on the books.

Finally, the decentralization of electric generation resources and the new technologies that empower individuals and businesses to be energy providers and price setters as well as consumers and price takers do not spell the end of the wired network of transmission lines. Those resources and technologies will depend more than ever on the grid for their economic justification and deployment. Transmission gives us the optionality to adapt electrically to whatever the future holds. Made smarter and more resilient, the transmission system will be the most valuable energy asset we have.

Thank you Mr. Chairman and Members of the Committee for your consideration.

With kind regards,

James J. Hoecker
Executive Director and Counsel, WIRES

Enclosure: Comments of WIRES filed in FERC Docket No. AD18-7-000

Cc: Jason Stanek (via Email)
   Senior Counsel, Committee on Energy and Commerce
June 5, 2018

The Honorable Tony Clark
Senior Advisor
Wilkinson Becker Knauer, LLP
1800 M Street, N.W.; Suite 800N
Washington, DC 20036

Dear Mr. Clark:

Thank you for appearing before the Subcommittee on Energy on Thursday, May 10, 2018, to testify at the hearing entitled “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, June 19, 2018. Your responses should be mailed to Kelly Collins, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Kelly.Collins@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
June 19, 2018

The Honorable Fred Upton
Chairman, Subcommittee on Energy
U.S. House of Representatives Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515-6115

Dear Chairman Upton,

Thank you for the invitation to testify before your Committee on May 10, 2018, at the hearing entitled, “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction and Alternatives.”

Enclosed are my responses to the questions for the record that were provided to me earlier this month.

Please do not hesitate to contact me if I may be of further assistance.

Sincerely,

/s/ Tony Clark
Senior Advisor
Wilkinson Barker Knauer LLP
1. In your testimony, you said that transmission incentives may be ripe for review. As you know, the Energy Policy Act of 2005 directed FERC to create a program to award certain transmission rate incentives to transmission projects that qualified under the regime known as Order 679.

   a. What type of review do you think FERC should conduct on transmission incentive policy?

      Five years after Order No. 679, FERC undertook a Notice of Inquiry that resulted in the 2012 Policy Statement that provided further guidance regarding the Commission’s implementation of Order No. 679. It has now been over five years since the 2012 Policy Statement and there has been significant industry, regulatory and legal activity in the transmission space. I would suggest that given the number of transmission items sitting squarely before the Commission, including various court remands, now may be an opportune time to look at FERC transmission policy (including ROE policy and incentives) holistically. A Notice of Inquiry could be one vehicle for the Commission to begin that sort of dialogue, but the Commission has a number of regulatory tools to initiate a conversation on these matters.

   b. Is there anything Congress should do to amend the Federal Power Act?

      I do not have any suggestions for specific Congressional action in this regard.

2. As you know, the regulatory process for settling disputes over the appropriate base rate of return on equity for transmission was thrown into question by a D.C. Circuit decision more than a year ago. To date, this issue has yet to be addressed by FERC on remand.

   a. With no regulatory certainty with regard to FERC’s overall ROE policy, how is this affecting transmission development and financing.

      There are a number of outstanding court remands that are being watched by the transmission industry. These include the D.C. Circuit Court opinion you reference, as well as a separate decision from California related to the Commission’s incentive ROE adder routinely granted to utilities for joining Regional Transmission Organizations. Both transmission owners and transmission customers are very much interested in the outcome of these proceedings given the regulatory uncertainty that exists during their pendency.

   b. Do you see a chilling effect on investment at a time when the nation needs new transmission infrastructure?

      As a general matter, regulatory certainty in such matters lends itself to timely decision making with regard to capital outlays. Conversely, long-term uncertainty lends itself to indecision.
1. The Committee has concerns that FERC’s current application of the discounted cash flow (DCF) methodology for transmission ratemaking is not having the intended effect to attract capital and deploy critical new transmission infrastructure.

   a. Would you agree that DCF, as currently utilized by the Commission, is underperforming with respect to achieving these objectives? If so, why do you believe this is the case?

   In 2014, the Commission released Order No. 531, which adopted a two-step DCF methodology similar to that used by FERC when establishing natural gas pipeline rates. Included in Order No. 531, was a Commission determination to select the midpoint of the upper half of the zone of reasonableness for setting base rates, due to unusual capital market conditions. FERC, however, was not successful in defending Order No. 531 before the D.C. Circuit Court of Appeals, so the current and future status of the DCF methodology’s performance is the subject of much uncertainty.

   b. Do you believe FERC’s current application of the two-step DCF model should be reevaluated? Should the Commission review the assumptions and data inputs that form the basis of its two-step DCF model?

   With the court remand of Order No. 531, I believe the time is now ripe for the Commission to consider many transmission investment issues holistically. This review could include consideration of the mechanics of the DCF methodology, transmission incentives, and the decision making process the Commission employs when deciding whether to send a transmission compliant to hearing.

   c. What, if any, “fixes” to the Commission’s application of DCF might FERC consider? Also, what, if any, alternative models or methodologies might the Commission consider in lieu of or in addition to the DCF model to better account for factors and conditions not considered by the DCF model, including measures of capital market risk?

   Should the Commission choose to change its ROE-setting methodology, yours is among the most difficult questions the Commission will attempt to answer. Unfortunately, there is no simple answer and no silver bullet.

   Consistent with Congress’ directives and the Federal Power Act, FERC should ensure that any methodology it chooses results in ROEs that are appropriately constructive to transmission investment. Commission policy needs to provide a relatively stable and predictable methodology for calculating ROEs while not being so rigid that it precludes the Commission from ensuring that transmission investment remains appropriate in changing economic conditions.

   Any change will inevitably result in litigation and, as the court remand in Order No. 531 proves, persuading a court when making a regulatory policy shift can prove challenging. If the Commission determines its existing methodology no longer produces just and
reasonable returns given the investment risk associated with constructing transmission, there are several refinements the Commission could consider, including different models for ROE-setting that are employed by regulatory bodies both in the U.S. and internationally.

The Commission will also need to decide how it would implement a change in policy. In Order No. 531 it altered the methodology via a contested complaint case, but the Commission could also choose to open a broader inquiry through an industrywide rulemaking proceeding. Each approach has its advantages and disadvantages which the Commission will want to assess. Regardless of if or how the Commission chooses to proceed, one recommendation I have is for the Commission to be as diligent as possible in how it communicates any changes to the broader stakeholder community. Regulatory surprises should be avoided since they can have unintended consequences on the entire utility sector and unduly chill needed investment.

The Hon. Richard Hudson

On April 19, PERC issued a new rule (Order No. 845) concerning revisions to the interconnection process for large generators which are over 20 MWs. The intent of this rule is to reduce the backlog of interconnection queue requests, however, these new regulations put the onus on the transmission provider to develop new procedures to accommodate additional flexibility for interconnecting generators. The interconnection process is already quite complicated with several studies often required to determine the impact of the new generation on the transmission grid with various deadlines for each specific step in the process. This was manageable when there were only a handful of interconnection requests in a year. However, these queues have grown more recently due to the significant increase in the number of smaller-sized interconnection requests for wind and solar generation. Developers typically put in several requests at one time, knowing that many of them will not get built. In some cases, there is more proposed generation in the queue than the total customer load in a particular area.

1. Do you believe that this new interconnection rule will alleviate those backlogs?

I believe the Commission may have missed an opportunity to better address some of the root causes of the ongoing queue backlogs. In my experience, queue backlogs are often the result of queues being flooded with speculative projects that may have limited chance of being brought to completion. When these speculative projects flow into and out of a queue they add frustrating uncertainty for other interconnection customers and the transmission providers. The problem can lead to time consuming delays when transmission studies need to be recompleted. Yet, as you correctly noted in your question, much of the bulk of the regulatory mandates in Order No. 845 fall to the transmission providers rather than adopting tools that would more rationally streamline the queues to those projects that have the best chance of advancing expeditiously. I am concerned that unless the Commission addresses the root causes of the backlogs,
especially the problem of so many speculative projects cluttering the queues, the problem will persist.

2. How would modifications made by interconnection customers affect the interconnection studies of later-queued requests?

Your question gets to the heart of the problem of a large unwieldy interconnection queue process. As speculative projects drop out of the queue or if they seek to modify their project, it can cause a cascade of circumstances that affect other projects in the queue.

3. Would you agree that vertically-integrated utilities may already be better positioned with aggressively grid resilience in transmission planning since generation, transmission and distribution needs can be evaluated holistically through the IRP process?

Undoubtedly, one of the strengths of the vertically integrated utility model is in its ability to plan generation, transmission and distribution facilities in a way that ensures public imperatives are met in relation to resilience, reliability, affordability and fuel source security and diversity.

The Hon. Scott Peters

1. As climate change continues and we see more frequent and more intense natural disasters destroying our grid, how is the grid affected in terms of capital costs and how do those costs affect consumers?

I have not personally conducted a study of the costs to the grid, and to consumers, related to a changing climate. Assessing the costs to individual utilities and their customers would likely be specific to each utility given the many differences that each face given the geographic diversity of the territories they serve.
Dr. Edward Krapels  
CEO  
Anbaric Development Partners  
401 Edgewater Place; Suite 680  
Wakefield, MA 01880  

June 5, 2018

Dear Dr. Krapels:

Thank you for appearing before the Subcommittee on Energy on Thursday, May 10, 2018, to testify at the hearing entitled “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, June 19, 2018. Your responses should be mailed to Kelly Collins, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Kelly.Collins@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton  
Chairman  
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
June 18, 2018

Kelly Collins
Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

RE: Responses to Additional Questions for the Record, "Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives"

Dear Ms. Collins,

Please find enclosed my responses to the additional questions for the record submitted by Representative Upton and Representative Hudson following my testimony before the Subcommittee on Energy on Thursday, May 10, 2018.

Hard copies of these responses will be mailed to you via FedEx, and an email copy of these responses will be sent to you at Kelly.Collins@mail.house.gov.

Please be in touch with any further questions.

Sincerely,

Edward N. Krapels
Chief Executive Officer
Anbaric Development Partners, LLC

401 Edgewater Place, Suite 680 | Wakefield, MA 01880 | T: 781-683-0711 | info@anbaric.com | anbaric.com
Question from the Honorable Fred Upton:

1. You are an infrastructure developer and you've actually built transmission projects, including an underwater DC cable connecting New Jersey with Long Island. As you know, DC lines have been around ever since Thomas Edison championed the technology.

   a. Can you explain why high-voltage DC transmission lines are not more prevalent in this country?

   Answer: The US electric system was built from the inside out: from the cities to the country. As a result, electric systems were organized first where there were a lot of consumers and only much later was electric service extended out to rural areas. Not accidentally, extension to the countryside required an act of congress (The Rural Electrification Act of 1936). It was natural that the incentives of electric companies was to economize on the transmission side of the business. Better short distances to consumer demand areas than long ones, and AC was cheaper from that perspective than DC, which always needs a considerable investment in converter stations (converting from AC to DC on one end, and DC to AC on the other end of the transmission line).

   Where electricity had to be transmitted a very long distance (which only made economic sense if the remote generating sources was especially desirable), DC technology received greater consideration. Thus, the Pacific Intertie was built in the 1980s to allow California to obtain power from the Columbia River hydro system, and the Quebec – New England DC project was built in the 1990s. Also, in the 2000s, a series of DC projects (Cross Sound Cable, Neptune and Hudson) were built to connect the downstate New York market to New Jersey and Connecticut.

   These projects constitute a tiny fraction of the overall North American transmission system. This stands in marked contrast to the American acceptance of the interstate highway system as the lifeblood of transportation commerce. The highway system, however, was a creature of the federal government. Washington has never placed the same political clout behind the building of an interstate electric transmission system. FERC's efforts to stimulate interregional transmission have largely been unsuccessful.

   b. What are the major benefits of DC over AC transmission?

   Answer: Direct current is more controllable than alternating current, and it experiences smaller line losses over longer distances.

2. In a recent article in the Electricity Journal you wrote that interregional coordination almost always reaches a dead end because transmission planners only care about the reliability of their own systems without having to rely on neighboring regions.

   Answer: Over the last two decades, innovative elective interregional transmission ideas have cropped up all over the country in response to the opening of transmission to competition by federal and most state regulators, but very few have been built. In the West, several multibillion dollar power lines are under development that would connect the resource rich areas of Wyoming, Nevada, and New Mexico to California. In New England, new transmission proposals are competing to better the links with Quebec and the Maritimes. In the mid-continent, bold transmission initiatives would connect previously
unconnected states and provinces. In each of these areas, inter-regional electric trade is touted as a
beneficial result of new infrastructure. After all, transmission is to the power business what the interstate
highway system is to the broader economy: it is the infrastructure that facilitates trade to the benefit of
both sides of the line. Those who can make electricity more cheaply can transmit to those where it is more
costly. Both sides benefit.

This is why FERC issued “Order 1000” in 2011, to accelerate the development of interregional
transmission lines. Seven years later, however, little has been done in pursuit of this laudable objective,
and this paper will argue that little has been done because FERC was not sufficiently prescriptive in how
interregional projects should be treated by those who have the power to approve and maintain them at a
regional and state level.

The new FERC commissioners appointed by President Donald Trump have a number of opportunities to
free the development of innovative interregional transmission proposals from regulations that not only
discourage anyone from proposing new projects, but render existing projects uneconomic. The
development of new interregional transmission lines should be an important federal policy goal for the
Trump Administration because it will promote economic growth within the United States. To get that
growth, FERC needs to develop a more prescriptive policy on how such projects can be originated and
how their cost should be allocated.

The primary reason to build interregional transmission lines should be similar to the primary reason to
build the interstate highway system: as infrastructure that unites the states, and enables economic growth.

a. If we had this mentality, highways would end at state borders and we would not have an
interstate highway system. How can we encourage or direct the development of inter-regional
transmission lines?

Answer: A key factor allowing the federal government to finance the majority of the cost of the interstate
highway system was the willingness of President Eisenhower to promote and Congress to support the
National Interstate and Defense Highways Act of 1956. It provided a new federal gasoline tax that was
instrumental in the financing of this massive project. In contrast, no President to my knowledge has ever
supported legislation to create an electric superhighway, nor has Congress initiated and passed such
legislation. Without a federal push, it is extremely unlikely that the states – who have massively different
electric market preferences – will provide the energy or the funding to create one.

Extremely complex and unpredictable interconnection procedures, “mitigation” and regional transmission
cost allocations imposed on “outside” customers have huge implications for interregional transmission
projects. If they continue to be applied to new interregional transmission projects, very few will be built
and some existing projects will become uneconomic. In many parts of America, transmission
development is already incredibly difficult and demanding. Both existing and new penalties on
interregional projects make it almost impossible.

Prevent the damage these regulations wreak starts with FERC. First, FERC should finally follow up on
the promise made in Order 1000 and create a new category of cost allocation for interregional
transmission lines. The narrowest version of “beneficiary pays” is simply too restrictive, because it tends
to rely too heavily on a static analysis of the effects of transmission. In conventional electric power
market thinking, a powerflow model will show that a new transmission line will raise the price in the
“source” market and lower it in the “sink” market. But that static picture is never the entire picture.
Instead, a transmission line changes the dynamic topography of the region in which it sits: it creates a new dynamic that in one year might be to the advantage of the source market, and another year to the sink market. The courts have made this more difficult by insisting on extremely narrow "beneficiary pays" formulations that, had they applied to interstate highways, the interstate highways system would never have been built.

Second, FERC should direct all ISOs and RTOs to refrain from imposing mitigation rules on interregional transmission lines. States have a right, and some would argue the federal government has a responsibility, to encourage interregional transmission and thereby enhance competition. The mitigation rules prevent that from happening by raising, not lowering, barriers to entry.

Third, FERC must not allow ISOs and RTOs to impose disproportionately large costs on interregional transmission lines. Imposing costs on "foreigners" (THAT IS, American consumers in regions that receive power exports) is irresistible. While export customers should pay their fair share of maintaining reliability in the regions from which they import electricity, they should not be victims to the kind of extremely disproportionate allocations they have suffered in recent PJM procedures.

The new FERC of the Donald Trump era has an opportunity to dismantle the triple jeopardy. With that, not only New York, Connecticut, and New Jersey but also other parts of the country can get on with the development one of the critical components of the Administration's infrastructure policy, and make electric America great again.

Question from the Honorable Richard Hudson:

On April 19, FERC issued a new rule (Order No. 845) concerning revisions to the interconnection process for large generators which are over 20 MWs. The intent of this rule is to reduce the backlog of interconnection queue requests, however, these new regulations put the onus on the transmission provider to develop new procedures to accommodate additional flexibility for interconnecting generators. The interconnection process is already quite complicated with several studies often required to determine the impact of the new generation on the transmission grid with various deadlines for each specific step in the process. This was manageable when there were only a handful of interconnection requests in a year. However, these queues have grown more recently due to the significant increase in the number of smaller-sized interconnection requests for wind and solar generation. Developers typically put in several requests at one time, knowing that many of them will not get built. In some cases, there is more proposed generation in the queue than the total customer load in a particular area.

1. Do you believe that this new interconnection rule will alleviate these backlogs?

As summarized by the reporters at UtilityDive, "more closely aligning output and nameplate capacity will help improve the interconnection process...[in which] there is also a recurring problem of late interconnection request withdrawals that can lead to interconnection restudies that can increase costs and timelines for other participants in the interconnection queue... Order 845 requires transmission providers to allow for provisional interconnection agreements for limited operation of a generating facility prior to completion of the full interconnection process. The order also requires transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection."
These changes are likely to further increase the number of interconnection proposals, and possibly contribute to an even greater backlog. In a way, this is good news: it indicates that competition for customers is increasing instead of abating, which Congress should welcome. To the extent this increases the burden on ISOs and RTOs, it would seem better to give them more resources to handle the demand than to choke off the transformation these interconnection requests are ushering in.

2. **How would modifications made by interconnection customers affect the interconnection studies of later-queued requests?**

It will increase the complexity of the interconnection process. Again, this is a sign of a vibrant and changing market, not a problem to be alleviated by limiting the flexibility of interconnection requests.

---

Edward N. Krapels
Chief Executive Officer
Anbaric Development Partners, LLC
June 5, 2018

Ms. Jennifer Curran  
Vice President, System Planning  
Midcontinent ISO  
720 City Center Drive  
Carmel, IN 46032  

Dear Ms. Curran:  

Thank you for appearing before the Subcommittee on Energy on Thursday, May 10, 2018, to testify at the hearing entitled “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, June 19, 2018. Your responses should be mailed to Kelly Collins, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Kelly.Collins@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton  
Chairman  
Subcommittee on Energy  

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy  

Attachment
Via Overnight and Electronic Delivery

June 19, 2018

The Honorable Fred Upton, Chairman
Committee on Energy and Commerce
Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515-6115

Dear Chairman Upton:

Thank you for the opportunity to appear before the Subcommittee on Energy on Thursday, May 10, 2018 to testify at the hearing entitled “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction and Alternatives.”

Pursuant to your letter of June 5, 2018, containing additional questions for the record submitted by Members following the hearing, attached please find my responses to those questions.

Please do not hesitate to contact me should you have any questions regarding the attached responses to the additional questions for the record. You may also contact Kurt Bilas, MISO’s executive director of government relations, in our Washington, D.C. office, at (202) 309-3550, or kbilas@misoenergy.org.

Sincerely,

Jennifer Curran
Vice President, System Planning
Midcontinent ISO

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy
Ms. Kelly Collins, Legislative Clerk, Committee on Energy and Commerce

Attachment: QFR Responses_20180510 Energy Subcommittee Hearing_Curran.docx
Jennifer Curran  
Vice President, System Planning 
Midcontinent Independent System Operator, Inc. (MISO) 

Responses to Member’s questions for the record for the House Subcommittee on Energy’s May 10, 2018, hearing entitled “Examining the State of the Electric Transmission Infrastructure: Investment, Planning, Construction and Alternatives”

Questions from the Honorable Fred Upton

1. FERC Order 1000 requires that certain transmission projects be competitively bid. I understand that MISO has opened just two bidding opportunities for projects under Order 1000. Other RTOs such as ISO-New England have not offered any opportunities for competitive bidding, and your neighbor, SPP, has offered just one, which failed.

   a. Why does it appear that RTOs are not opening up transmission projects for competitive bidding?

MISO’s competitive transmission process identifies two project types that are eligible for competitive developer selection – Market Efficiency Projects (MEPs) and Multi-Value Projects (MVPs).

Since FERC’s acceptance of MISO’s competitive transmission process in 2015, MISO has approved three MEPs. Two of these were opened for competitive developer selection – the Duff-Coleman Project in 2015 and the Huntley-Wilmarth Project in 2016 (which was awarded to the incumbent following an applicable state right of first refusal statute). A third MEP, the Hartburg-Sabine Junction 500 kV Market Efficiency Project, was identified in 2017 and is currently undergoing the selection process.

Order 1000 focused on reducing barriers to regional projects, which tend to be cyclical in nature. To be eligible for competitive selection in MISO’s region, transmission projects must meet certain criteria, including a benefit-to-cost ratio where benefits are equal to or exceed costs. In 2011, prior to Order 1000, MISO approved a major set of regional investments – a portfolio of seventeen MVPs across its footprint, representing approximately $6 billion in transmission system investment. The projects were designed to reduce system congestion and meet Renewable Portfolio Standards in several MISO states through 2026. The last project will go into service in 2023.

As the resource portfolio continues to shift, MISO believes that the strength of its planning process will continue to identify regional projects that demonstrate value.

2. We’ve heard multiple times that interregional transmission lines simply are not being constructed. Can you explain why?

Order 1000 allows adjacent regions to explore potential solutions that may be more cost effective or efficient than regional or local solutions. Interregional projects must show benefit for both regions. MISO’s experience has shown that most transmission needs can and are being addressed by more cost effective and efficient regional or local solutions.

MISO, which covers an expansive geographic footprint across 15 states and one Canadian province, has facilitated nearly $30 billion in total transmission investment, which includes interstate transmission, since the first MISO Transmission Expansion Plan in 2003.
Interregional planning under Order 1000 is a relatively recent development. While MISO has nearly 15 years of regional transmission planning experience, Order 1000 interregional compliance filings were made during 2013 and compliance orders were issued through the end of 2015. As a result, interregional planning has been slower to evolve as we bridge regional differences. Further, the pace of interregional project development, as well as recent larger scale regional transmission efforts, has been significantly impacted in recent years by several factors, including the need to evolve the metrics used to assess the benefits of transmission to reflect changing system conditions. The uncertainty of the future energy landscape and lack of clear policy to address that future uncertainty continues to hinder the business case for long-lead, large scale transmission projects.

Transmission investment provides value to the marketplace by opening up opportunities to access the most economic resources on the system. That access and ability to maximize the benefit of interregional transmission can be hindered by administrative or economic hurdles, which in some cases reflect differing operating philosophies and are difficult to overcome. In general, it is difficult to achieve alignment and agreement of future needs, benefits and cost allocation across multiple regions that are geographically expansive and contain a diverse spectrum of stakeholder opinions. A high level of consensus is critical when moving forward with interregional projects.

Nevertheless, MISO and PJM have made significant progress that our regions can build from. We jointly developed and implemented a new transmission concept called Targeted Market Efficiency Project (TMEP) upgrades. TMEPs are designed, in the short-term horizon, to address historically known market-to-market congestion. MISO and SPP are also working with our joint stakeholders on how best to incorporate market-to-market congestion in coordinated transmission planning. While these projects are relatively smaller upgrades, they will have a large positive benefit to the seam between regions, and we expect them to pave the way for future mutually beneficial projects.

Together with PJM, SPP and our joint stakeholders, we are working to further remove perceived barriers to enable the evaluation and potential approval of larger, more cost effective and efficient interregional projects and to enhance our processes to find efficiency gains. We anticipate adding such enhancements to our Joint Operating Agreements this year.

3. MISO was very successful with its Multi-Value Project (MVP) effort. Can you explain in more detail how the MVP process works and how it’s different than the Order 1000 planning process?

MISO’s planning process included many major elements of FERC Order 1000, even before that Order was issued. For example, MISO employed a regional planning process that included consideration of public policy needs and had a regional cost allocation mechanism (Multi-Value Projects, or MVPs) for those types of projects. MVPs are a category of transmission expansion projects that look at portfolios of projects that provide widespread benefits throughout the MISO region. MVPs address public policy requirements, reliability and economic benefits.

In order to be recommended as MVPs, the proposed project portfolio must also meet a series of conditions:

- aligned interests for regional transmission solutions;
- a robust business case for the projects that evaluates the projects under multiple future scenarios;
clearly defined cost allocation methods that closely align who pays with who benefits; and

• cost recovery mechanisms that reduce financial risk.

All of these items are evaluated through an open and transparent stakeholder review process. To provide additional insight and confidence into the planning process, MVPs also undergo periodic reevaluation through MVP annual and triannual reviews.

In 2011, MISO’s Board of Directors approved 17 projects, representing approximately $6 billion in transmission system investments, as the first MVP portfolio. While the original MVP portfolio was developed prior to the implementation of FERC Order 1000, many of the planning reforms specified by the Order were already applied to the MVP planning effort. The MVPs were demonstrated to have broad regional benefits well in excess of costs, aligned to corresponding region-wide cost allocation mechanisms. The portfolio also had widespread support from state and regulatory agencies to help meet an important policy need at the time – state Renewable Portfolio Standard (RPS) mandates.

Today, the MVP project category is a part of MISO’s Order 1000-compliant regional planning process. Projects that qualify as an MVP are regionally cost shared on a load ratio share basis (based on energy withdrawals). Because MVPs are regionally cost shared, future MVPs are eligible for MISO’s competitive developer selection process.

a. In terms of allocating the costs of transmission projects, how does MISO seek to ensure that beneficiaries pay for transmission?

MISO employs a suite of mechanisms designed around allocating the costs of transmission projects to beneficiaries.

• Cost allocation for reliability driven projects is focused on the entity that is facing a reliability need and is thus benefitting from the project.

• Cost allocation for projects needed to interconnect new resources is focused on those customers seeking to gain access to the MISO transmission system. For higher voltage upgrades (defined as those transmission facilities 345kV and up) there is a ten percent allocation to all load in MISO in recognition of the broader efficiency impacts those facilities provide.

• Cost allocation for projects to improve market efficiency is based on the distribution of calculated benefits for those projects, utilizing multiple quantifiable metrics.

• Cost allocation for portfolios of projects that benefit the MISO region is done on a load ratio share basis. These portfolios of projects (MVPs) can be driven by public policy needs or a combination of economic and reliability factors. To ensure alignment of costs and beneficiaries MISO evaluates MVPs as a part of a portfolio of projects that impact the region.

MISO also regularly reviews cost allocation mechanisms with stakeholders and adjusts the methods as necessary for new projects to reflect changing system conditions. The development of the Multi-Value Project cost allocation method is an example of the outcome of one such stakeholder review.

Questions from the Honorable Gregg Harper

3
1. Under FERC's incentive policy provided certain ROE rate incentives for transmission providers to build projects that either faced unique risks or employed advanced technologies.

   a. From your perspective as a grid operator, do these incentives attract needed transmission infrastructure investment?

Many different factors, including rate incentives, are taken into account by transmission providers in making transmission infrastructure investment decisions. As an RTO, MISO's planning processes focus on identifying benefits of projects to the system, but we do not build or own transmission infrastructure.

   b. In your opinion, would many of these projects still get built without the incentives?

Because MISO does not build or own transmission lines or recover their costs, it is difficult to accurately predict how much impact incentives have on the business decisions of individual transmission providers.

---

**Question from the Honorable H. Morgan Griffith**

1. Given the difficulties you mention achieving consensus on who should pay for large new transmission investments, would clearer FERC policy on cost allocation address another impediment to building the next set of large transmission projects?

Cost allocation is inherently challenging. However, there are some elements of cost allocation where further FERC guidance would be helpful, in particular around which benefits should be quantified in the evaluation of regional transmission projects. Transmission, particularly large scale Extra-High-Voltage transmission, provides many benefits to multiple parties. It is critical that the full scope of benefits are included in the analysis to determine the merits of a project.

FERC Order 1000 established that cost allocation should be based on a beneficiary pays principle. However, because regional transmission provides multiple types of benefits to multiple parties, to allocate to beneficiaries you must first identify who is benefiting and why. Some benefit metrics, such as Adjusted Production Cost savings, are widely utilized and understood throughout the industry. Other metrics based on new technologies or initiatives are more difficult to quantify and gain acceptance. For example, there is an increased focus in the industry around system resilience but, to date, there is no widely accepted method to quantify the economic benefit of regional transmission investment to overall system resilience. FERC or industry efforts to define and quantify an economic metric associated with improved system resilience could help integrate those elements into regional planning processes.

---

**Questions from the Honorable Richard Hudson**

On April 19, FERC issued a new rule (Order No. 845) concerning revisions to the interconnection process for large generators which are over 20 MWs. The intent of this rule is to reduce the backlog of interconnection queue requests, however, these new regulations put the onus on the transmission provider to develop new procedures to accommodate additional flexibility for interconnecting generators. The interconnection process is already quite complicated with several studies often required to determine the impact of the new generation on the transmission grid with various deadlines for each specific step in the process. This was manageable when there were only a handful of interconnection requests per year. However, these queues have grown more recently due to the significant increase in the number of smaller-sized interconnection requests for
wind and solar generation. Developers typically put in several requests at one time, knowing that many of them will not get built. In some cases, there is more proposed generation in the queue than the total customer load in a particular area.

1. Do you believe that this new interconnection rule will alleviate these backlogs?

While FERC's recent rule on generation interconnection procedures is an important step toward expediting interconnection queue processing, it will not be sufficient to alleviate MISO's current backlogs.

Prior to the issuance of Order 845 MISO had already instituted many of its provisions, and we continue to seek opportunities to improve our processes. Some of the challenges we face include queue size and related process delays due to interconnection study complexity. MISO currently has over 90,000 MW of requests in our generator interconnection queue. This is over half of MISO's current total installed generation capacity of 175,000 MW.

Historical experience and discussions with customers suggest many of the projects in the queue will not be built. The sheer size of the existing queue creates challenges that are preventing those projects that are ready and prepared for commercial operation from getting their Generation Interconnection Agreements in a timely manner.

MISO continues to work with stakeholders to develop reforms to help expedite the process and move projects through the queue more quickly. The near term focus includes changes to site control requirements and system study processes, and modifications to generation study models.

2. How would modifications made by interconnection customers affect the interconnection studies of later-queued requests?

MISO's process is designed to ensure that modifications do not adversely affect the results of later-queued requests. Any request for modifications must be evaluated by MISO to determine the potential impact on later-queued project requests. If the requested modification is determined to impact the cost or time, including study time, for a lower queued project, then MISO will deny the modification request or require the interconnection request to re-enter the queue.

Question from the Honorable Tim Walberg

1. You note that FERC Order 1000 and the advent of competitive bidding is one of the items that has increased the complexity of developing additional large scale investment plans. Can changes to this policy remove some of the challenges to developing the next set of regional transmission investments needed in MISO?

Refinement of Order 1000 would reduce the complexity of and potentially improve the collaboration around development of transmission investments in MISO's region. Key to the refinement is that FERC establish a clear, holistic view of the objectives and success measures for transmission investment. MISO's focus, first and foremost, is ensuring that necessary regional and interregional transmission – the most efficient plans to provide benefits to customers in excess of costs – is developed in the region. Metrics that reflect those objectives, rather than simply counting the number of projects in a specific category, would be welcomed.
June 5, 2018

Dr. Ralph Izzo
Chairman, President, and CEO
Public Service Enterprise Group Incorporated
80 Park Plaza
Newark, NJ 07101

Dear Dr. Izzo:

Thank you for appearing before the Subcommittee on Energy on Thursday, May 10, 2018, to testify at the hearing entitled “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, June 19, 2018. Your responses should be mailed to Kelly Collins, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Kelly.Collins@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
Additional Questions for the Record

"Examining Transmission Infrastructure: Investment, Planning, Construction and Alternatives"

House Energy and Commerce Subcommittee on Energy

May 10, 2018

The Honorable Fred Upton

1. PSEG opposed Order 1000 from the start when it was initially proposed in 2010. Setting aside the concerns you have with the transmission planning process, do you believe that there should be competition among incumbent utilities like PSEG and new transmission developers? If no, why not?

   A: As a general principle, competition in any sector tends to drive down costs and spur innovation, both of which can benefit consumers. But competition is only an economic principle. Without the right rules driving to the right outcomes, consumers can still be on the losing end.

   When it comes to implementation of Order 1000 in PJM, neither the rules nor the resulting outcomes are in the customer’s long-term interest. If I held a competition to build a car but didn’t specify whether I wanted a Rolls Royce or a Yugo or a school bus, competitors would spend a lot of money trying to guess what I wanted, and I’d be stumped as to how to fairly evaluate the merits of such wildly different solutions. Moreover, if my only objective were to minimize my up-front cash outlay, solutions that provide longer term value, durability, or greater optionality at a higher initial cost would not even make the cut.

   Keeping initial costs low for consumers is an important objective, but it needs to be balanced against other important outcomes such as grid resilience, adaptability and reliability over the long-term. If band aid solutions for grid upgrades become the default choice, customers will surely face higher costs over the longer term.

   Order 1000 implementation is not living up to the ideals of a competitive, efficient process. In PJM we have seen significant confusion and chaos erupt as the RTO grapples with apples-to-oranges cost comparisons and how to interpret developer cost cap commitments. We’ve seen the RTO reach beyond its expertise to try to assess which projects can get environmental permits, and try to mediate thorny political disputes between states. At a more basic level, there is an unsettling lack of clarity over which entity will be accountable for the ongoing hands-on management of the contract with a chosen developer to execute a project. Is it the RTO? Is it FERC? As anyone who has
undertaken a home renovation can tell you, this is not something that can be left on auto pilot.

2. In your written testimony, you provided a number of bullets highlighting some disappointing facts. Notably, not one of the non-RTO planning regions have provided even a single competitive transmission bidding opportunity, and that in the RTO regions there have just been a handful of bidding opportunities.

   a. While I recognize that you are advocating for the outright repeal of Order 1000, do you believe that there is any way to salvage FERC’s competitive transmission development objective?

      A: PSEG recommends that the FERC pause implementation of Order 1000 until planning regions affirmatively demonstrate that the Order is providing value and not costing consumers more. Planning regions should also demonstrate that they have the processes and controls in place to successfully administer competitive bids and then oversee a developer’s commitment to build. For instance, if a developer agrees to cap their construction costs, this can save consumers money, but only if the developer is held to these commitments. As the RTOs themselves have conceded, they are not prepared or resourced for this important ongoing oversight role.

      Finally, to return to the car analogy, the Order 1000 process in PJM has been plagued by too many variables. Far from spurring innovation, this approach has tended to create paralysis. The collaboration that used to occur among grid planners and transmission owners across the region to design the best solution has been lost. Even if the rules can be ironed out, it may be best to narrow the application of Order 1000 to those projects that can bring economic value to consumers, and not apply it to critical reliability upgrades needed to maintain the grid.

3. We’ve heard some concerns that large investor-owned utilities (IOUs) may prefer to invest in capital-intensive transmission projects to increase their rate base instead of selecting less-expensive projects that can achieve the same effect at a lower cost to consumers.

   a. Do we have regulatory policies in place that create an incentive to spend more simply to increase utility’s rate base?

      A: Utilities like PSE&G are obligated under state law to provide safe and reliable service to customers. Our state officials and our customers expect us to keep the lights on and, if there is a problem, we are the first to receive a phone call. Thus, our focus and our priority at all times is on reliability of the system and making the necessary investments to ensure long-term reliability. Over the last 10 years, our investment in the
The transmission grid has resulted in a five-fold decrease in transmission outages on our system.

At the same time, we are required to identify cost-effective solutions, and there are several layers of review to ensure the investments are both necessary and prudent. First, our proposed transmission projects are reviewed extensively for cost-effectiveness and need by the independent grid operator and by other key stakeholders in the planning process before they ever get the green light. Second, when we site a project during the construction phase, our state commission or the impacted towns are required to review the project for cost effectiveness, need and availability of alternatives. Finally, as a rate-regulated company, all transmission projects are subject to the oversight of FERC, which has the authority to review our project costs and our rates to ensure they are just and reasonable and that our expenditures are prudent.

The Honorable Gregg Harper

1. As you know, FERC has effectively lacked a return-on-equity (ROE) policy ever since the D.C. Circuit struck down its policy (i.e., Opinion No. 531) more than a year ago. In the absence of a clear and stable ratemaking policy, how are transmission owners and developers responding to this uncertainty? As a CEO of a major utility with transmission projects, what is your perspective on this matter?

A: In order to build, own, and operate adequate transmission infrastructure that ensures reliable and affordable service to customers, transmission owners and developers require that FERC establish a clear and consistent ratemaking policy. Because transmission infrastructure involves a long-term commitment, often 40 years or more, investors require adequate and stable returns over the long-term to provide financing for resilient and sound infrastructure development. As the Commission considers its ROE policy, it must examine whether its methodology is sufficient to attract the capital necessary to meet transmission investment needs at a time when the transmission system needs to replace aging infrastructure, enhance resilience and accommodate a changing generation resource portfolio.

The Honorable Richard Hudson

On April 19, FERC issued a new rule (Order No. 845) concerning revisions to the interconnection process for large generators which are over 20 MWs. The intent of this rule is to reduce backlog of interconnection queue requests, however, these new regulations put the onus on the transmission provider to develop new procedures to accommodate additional flexibility for interconnecting generators. The interconnection process is already quite complicated with several studies often required to determine the impact of the new generation on the transmission grid with various deadlines for each specific step in the process. This was manageable when there were only a handful of interconnection requests in a year. However, these queues have grown more recently due to significant increase in the
number of smaller-sized interconnection requests for wind and solar generation. Developers typically put in several requests at one time, knowing that many of them will not get built. In some cases, there is more proposed generation in the queue than the total customer load in a particular area.

1. Do you believe that this new interconnection rule will alleviate these backlogs?

2. How would modifications made by interconnection customers affect the interconnection studies of later-queued requests?

A: Through Order 845, FERC has implemented significant reforms that should help to mitigate some of the backlogs in the interconnection queue. However, it is unlikely that these reforms will completely alleviate backlogs, in part because developers want and need flexibility (and therefore put in multiple requests and/or change their queue requests) and in part because the RTOs are trying to ensure that generators pay their appropriate share of costs rather than having these costs shifted to customers. PJM has actually made significant progress in clearing up the queue backlog over the last several years, and the FERC order should continue to help.
Dear Mr. Twitty:

Thank you for appearing before the Subcommittee on Energy on Thursday, May 10, 2018, to testify at the hearing entitled “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, June 19, 2018. Your responses should be mailed to Kelly Collins, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Kelly.Collins@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
June 19, 2018

Chairman Fred Upton
Subcommittee on Energy
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

VIA ELECTRONIC DELIVERY

Dear Subcommittee Chairman Upton,

It was a pleasure to testify before the Energy Subcommittee on Thursday, May 10, 2018, at the hearing entitled "Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction and Alternatives"

In response to your request dated June 5, 2018, for additional information for the record, I respectfully submit the attached response to the questions posed by you and other members of the Committee.

Thank you for your continued interest in the electric markets and the work the subcommittee is undertaking in the Powering America series. The electric sector is undergoing a period of significant change and Congressional oversight is appropriate at this time.

Sincerely,

John Twitty

Attachment: "TAPS Response to House E and C QFR"
Responses to Additional Questions for the Record

The Honorable Fred Upton

1. In 2012, the Commission issued a policy statement encouraging transmission developers seeking rate incentives to participate in joint ownership arrangements (JOAs). FERC found that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks. From your perspective have transmission developers been willing to partner with your utilities [as encouraged by] FERC’s policy statement in 2012?

Response:

Although the Commission’s 2012 Incentive Policy Statement correctly recognized the benefits of joint ownership arrangements and sought to encourage them, this encouragement has proven insufficient to induce large transmission owners and other developers to enable small embedded load-serving entities to invest in their share of the grid. As a result, the answer to your question is generally no—developers have generally been unwilling to partner with transmission-dependent load-serving entities. Incumbent utilities have been even less willing to do so.

GridLiance, a non-incumbent transmission developer focused on partnering with public power entities and cooperatives,1 is a limited exception to that general statement. However, although a number of Transmission Access Policy Study Group (“TAPS”) members have engaged with GridLiance in proposing projects, there has been little tangible progress. In part that has been due to the failings of the Order 1000 planning process, as currently implemented. FERC Staff’s own analysis shows that in 2016, no proposals submitted by nonincumbent transmission developers were selected by any of the transmission planning regions that had competitive proposal windows2—a strong indication that the Commission’s effort to foster more efficient and cost-effective transmission development through competition is significantly flawed.

2. Your testimony suggested that FERC must do more to make sure that grid planning encompasses all entities that use the grid for delivery of electric energy to consumers. What suggestions would you have for Congress to encourage FERC to assure that planning is more inclusive?

Response:

Congress should exercise oversight authority to inform FERC that this is a priority for the Committee, and urge FERC to do more to encourage joint ownership arrangements. There is much that FERC can do to achieve this important objective.

1 http://www.gridliance.com/.

For example, FERC can use its authority under Section 219 of the Federal Power Act ("FPA"), which provides for incentive-based transmission rates, to more directly link incentives to willingness to enter into joint ownership arrangements. Specifically, those seeking transmission rate incentives, particularly incentive equity returns, should not be permitted to turn away load-serving entities in the footprint seeking to make their load-ratio investment in the grid. Instead, a showing that the applicant has offered such investment opportunities on reasonable terms should be a prerequisite for incentives. Similarly, Congress could urge FERC to also explore using its other authority to encourage joint transmission ownership. For example, the willingness to offer load-serving entities in the footprint an opportunity to make their load-ratio investment in the grid on reasonable terms could be a consideration when evaluating whether a proposed merger is in the public interest.

In addition, FERC's Order 1000 transmission planning process can be a more effective vehicle for fostering inclusive transmission investments. As described in my May 10, 2018 written testimony at pages 5-6, Order 1000 also recognized the value of and encouraged joint ownership arrangements, but more can be done to achieve that objective. Non-incumbent transmission developers, especially those (like GridLiance) that accommodate participation by small load-serving entities, should have a fair opportunity to compete to develop needed new transmission. Indeed, a developer's inclusiveness of small load-serving entities would merit positive consideration in the selection process. Unfortunately, despite Order 1000's efforts to promote a competitive transmission development process and vigorous competition for those projects that have been open to competition, positive results have been limited, as FERC's own analysis confirms (as noted above). As discussed on pages 13-14 of my written testimony, Congress should encourage the Commission to revisit and reinvigorate the Order 1000 competitive transmission development process in a manner that will promote joint transmission ownership, as well as use competitive discipline to curb rising transmission costs.

FERC's exercise of the full range of its FPA authority to promote joint ownership, as urged above, would fulfill Congress' directive in FPA Section 217 by enabling load-serving entities to directly participate in ensuring that their reasonable needs are satisfied, and would allow them to offset the increasing cost of transmission, benefiting consumers and businesses.

3. In the Powering America hearing series, the Committee has heard concerns that the RTOs may not be functioning as originally intended. Your members have assets and serve customers in virtually all of the RTOs. Can you tell me the biggest problems your members face in the RTOs and what can be done to better address the concerns?

Response:

As you correctly note, TAPS members serve customers in virtually all the RTOs. In fact, even though they are relatively small, a number of TAPS members have loads and diverse resources in multiple RTOs due to the RTO-membership decisions of large transmission owners. Large transmission owner changes in their RTO membership can significantly impact the ability of our members to continue to use their long-term resources to serve their loads. As discussed in my written testimony at pages 10-11, such changes can create an RTO seam that disrupts the long-term power supply arrangements of embedded load-serving entities that have loads and/or resources on the larger transmission owners, significantly increasing the costs and risks to which
the smaller utility and its customers are exposed. Nevertheless, FERC generally offers little or no protection to such embedded utilities when such RTO membership changes occur. Indeed, rather than fulfill its FPA Section 217 obligations to preserve and honor the load-serving entity’s long-term rights to firm delivery of its capacity resources to it load, the Commission has accepted new RTO resource adequacy requirements that aggravate the adverse impacts.

Capacity markets are a significant concern to TAPS members. TAPS members in the eastern RTO face mandatory capacity “markets,” which are administrative constructs that include features that undermine the members’ traditional, obligation-to-serve business model. For example, the ISO New England and PJM tariffs include minimum offer pricing rules (“MOPRs”). TAPS members in those regions undertake long-term power supply commitments to fulfill their load-serving resource adequacy obligations. Under the MOPRs, however, they may have to purchase capacity a second time if the minimum offer price imputed by the RTO to those long-term capacity resources causes them not to clear in the capacity “market.” Continuously changing rules and performance requirements also can disqualify their long-term resources from being counted for resource adequacy. Such restrictions undermine the ability of public power entities to make the long-term power supply commitments that Congress sought to protect through FPA Section 217, and which have a proven track record of supporting reliability, adequacy, and resilience. Nevertheless, in a recent decision, a divided FERC indicated receptivity to expanding MOPRs.3

So far, FERC has rejected efforts by Midcontinent Independent System Operator (“MISO”) and certain generators to import aspects of the mandatory eastern market capacity constructs into the MISO region, in which more than 90% of the load is subject to traditional state cost-of-service regulation. However, various generators continue to press for such changes in order to increase prices. Costs to consumers are also threatened by the Commission’s refusal to apply FPA Section 217’s directives to ensure delivery of the capacity associated with load-serving entity’s power supply arrangements, as I explain at pages 9-10 of my written testimony.

As my comments above highlight, minimizing cost to American consumers and businesses, who rely on electricity for economic and social well-being, is not the central focus of RTOs. Indeed, nearly a decade ago, FERC declined to mandate specific statements in RTO mission statements requiring RTOs to provide cost reductions and net benefits to the ultimate consumers they serve, and rejected other proposals to make RTOs more accountable.4 Particularly given the recent GAO findings that FERC lacks the data to assess RTO performance,5 Congress should exercise oversight to ensure that the FPA’s overarching consumer protection mandate is not forgotten.6

The Honorable H. Morgan Griffith

1. You stated in your testimony that the Joint Ownership transmission model has many benefits. What are some of the benefits over our current model and what steps can we do to increase joint ownership opportunities for transmission?

Response:

The joint ownership model provides numerous benefits. They include the following:

1. **Inclusive joint ownership makes joint planning real.** Although FERC has issued rules to promote open, inclusive, and transparent planning they have fallen short of accomplishing the goals. There is a big practical difference in how planning is accomplished when all load-serving entities are at the table as owners. Aligning the ownership structure of the grid with the reality of the way the network operates results in better planning. When diverse parties are owners, openness, transparency, and more balanced decision making flow automatically. The end result is more efficient grid investment and a more robust and resilient grid.

2. **Inclusive joint ownership results in a better and more efficient transmission system planned to meet multiple needs.** This has been the experience of TAPS members in Wisconsin, where combining five systems into one jointly owned transco (the American Transmission Company or “ATC”) has certainly led to a more rationally developed system than had balkanized planning and construction. We also see it in CapX2020, a joint initiative of 11 transmission-owning utilities in Minnesota, North Dakota, South Dakota, and Wisconsin formed to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The 800 mile, nearly $2 billion investment includes four 345-kilovolt transmission lines and a 230-kilovolt line. It is the largest development of new transmission in the upper Midwest in 40 years.

3. **The diverse support that joint ownership provides is very important in siting.** By meeting the needs of multiple utilities, a joint project is able to demonstrate multiple benefits. Although participation by municipals and cooperatives may be relatively small percentage-wise, these utilities bring a wealth of political support to the state approval process. This support can make all the difference in speeding up permitting and addressing local concerns. FERC explicitly recognized this benefit in its 2012 Incentive Policy Statement.

4. **Inclusive joint ownership arrangements provide the critical alignment of interests that makes it easier for state regulators to approve proposed transmission projects.** When state commissions are presented with projects that are least-cost because they meet multiple needs, when they see unity among the utilities on need, and when they are faced with a broad base

---

(1959) (requiring natural gas be sold “at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest”).

7 https://www.atcllc.com/.

of support from diverse stakeholders, it is far easier for them to grant requested authorizations.

5. **Inclusive joint ownership makes the cost allocation issue easier to resolve, although it still remains a thorny issue.** For instance, while ATC’s transmission rates have been increasing because of ATC’s construction efforts, municipal and cooperative owners, through their ownership in ATC, have been able to offset about 20% of those costs. This has made it easier for them to support needed ATC build-out. Similarly, investor-owned utilities that are able to participate in projects have an earnings opportunity, rather than simply an opportunity to pay.

6. **Inclusive joint ownership spreads the risk of major projects broadly and provides a variety of sources of capital for projects.** In a post-financial crisis world of tightened credit and tougher credit-worthiness standards, the financial diversity and strength achieved through joint ownership arrangements should be increasingly valuable. FERC explicitly recognized this advantage of joint transmission ownership as a risk reducing in its 2012 Incentive Policy Statement.

7. **The broad base of support achieved through joint ownership arrangements can be essential to securing state legislative action required to better align retail rate recovery with the need for supporting major transmission investment**, as has occurred in Minnesota with the full support of the CapX group.

8. **Inclusive joint ownership arrangements reduce the need for FERC to referee rate and other disputes.**

9. **Inclusive joint ownership arrangements benefit consumers.** The benefits listed above work together to produce transmission better designed to meet all needs, and that can be sited and built more quickly. As a result, inclusive joint ownership arrangements benefit consumers and reduce costs.

As to what steps that can be taken to increase joint ownership, step one would be to exercise oversight authority to inform FERC that this is a priority for the Committee, and urge FERC to do more to encourage joint ownership arrangements. There is much that FERC can do to achieve this important objective. Please see my response to the second question from Chairman Upton.

2. **How will we know when we’ve achieved a cost-effective, appropriate level of resilience?**

   a. **Do you think we have the data in place to measure resilience currently?**

Response:
In comments filed with FERC in its ongoing Grid Resilience proceeding, TAPS urged against a one-size-fits-all approach to identifying and addressing resilience challenges. Each region faces different resilience challenges, based on its particular resource and load mix, location, scope, market design, the retail regulatory systems of the states in its footprint, and regional differences in the pace and direction of the changes transforming the electric industry. Establishing priorities and metrics—a crucial first step toward any resilience program—will also require local knowledge and assessment of the costs and benefits of potential actions to improve resilience. The key question as to the level of resilience to be achieved can best be answered by balancing the interests of multiple stakeholder groups, with particular attention to state and local regulators, consistent with FPA Section 217(b)(4)’s directive to the Commission to facilitate planning for the reasonable needs of load-serving entities. TAPS urged FERC to allow RTO stakeholder processes time to build consensus on these complex issues.

As noted, the crucial question is: “what is resilient enough?” “Resilience” should not become a license for RTOs to gold-plate the system by taking unilateral actions that unduly drive up the costs to consumers, including transmission costs—an outcome fundamentally inconsistent with FPA Section 217(b)(4)’s directive to the Commission to facilitate planning for the reasonable needs of load-serving entities. It is always possible to build more redundancy into the grid or require ever higher levels of reserves, spare equipment, and personnel standing by. Therefore, to make “resilience” a useful and meaningful concept for evaluating and planning the grid, we have to decide: What are the scenarios that we want the system to be able to withstand? What are the specific restoration targets that we want to achieve? And at what cost?

The North American Electric Reliability Corporation’s (“NERC”) definition of “Adequate Level of Reliability” is instructive: it distinguishes (at 1) between predetermined Disturbances (“the more probable Disturbances to which the power system is planned, designed, and operated”) and “low probability Disturbances,” and recognizes that it may be appropriate to treat them differently. NERC states (at 4) that

[Bulk Electric System (“BES”)] owners and operators may not be able to apply any economically justifiable or practical measures to prevent or mitigate [the] Adverse Reliability Impact on the BES [of low probability Disturbances], despite the fact that these events can result in Cascading, uncontrolled separation or voltage collapse. For this reason, these events generally fall outside of the design and operating criteria for BES owners and operators.

---


11 A criterion for being certified by FERC as the Electric Reliability Organization is “the ability to develop and enforce . . . reliability standards that provide for an adequate level of reliability of the bulk-power system.” FPA § 215(c)(3), 16 U.S.C. § 824o(c)(3).
NERC's "Adequate Level of Reliability" definition thus recognizes (as Congress implicitly did by including the word "adequate" in the statute) that a requirement of "zero blackouts" is neither economically justifiable nor practically feasible.

Decisions about the degree of resilience and regional priorities necessarily entail judgments as to the risks and costs that consumers should bear. There must also be a requirement that the benefits of resilience measures outweigh their costs. Implementing this standard will not be easy: assessing the risks and benefits associated with mitigating high impact/low frequency events is difficult, particularly where investments may rapidly become obsolete as the electric industry continues to rapidly evolve. Moreover, they will have ramifications for matters outside the Commission's jurisdiction (e.g., retail service reliability and local distribution facilities); and the strategies available to achieve resilience may well require close collaboration with distribution utilities and relevant electric retail regulatory authorities. For these reasons, TAPS urged that determinations as to resilience priorities and measures should be addressed on a regional basis through the stakeholder process, with appropriate deference to state and local regulators. Moreover, the decision-making process to undertake resilience measures must be transparent, and the measures must be just, reasonable, not unduly discriminatory, cost-effective, and subject to FERC approval.

The Honorable Richard Hudson

On April 19, FERC issued a new rule (Order No. 845) concerning revisions to the interconnection process for large generators which are over 20 MWs. The intent of this rule is to reduce the backlog of interconnection queue requests, however, these new regulations put the onus on the transmission provider to develop new procedures to accommodate additional flexibility for interconnecting generators. The interconnection process is already quite complicated with several studies often required to determine the impact of the new generation on the transmission grid with various deadlines for each specific step in the process. This was manageable when there were only a handful of interconnection requests in a year. However, these queues have grown more recently due to the significant increase in the number of smaller-sized interconnection requests for wind and solar generation. Developers typically put in several requests at one time, knowing that many of them will not get built. In some cases, there is more proposed generation in the queue than the total customer load in a particular area.

1. Do you believe that this new interconnection rule will alleviate these backlogs?
2. How would modifications made by interconnection customers affect the interconnection studies of later-queued requests?

Response:

TAPS recognizes the challenges associated with the interconnection queue and backlogs. TAPS filed comments in the rulemaking proceeding leading up to Order 845 that generally supported the proposed reforms, which were drawn from lessons learned in RTO areas and reasonably balance the needs of interconnection customers with the needs of load and transmission.
providers. While TAPS is hopeful that the reforms will be helpful, we are unable to assess the specific impacts about which the questions inquire.

June 19, 2018

---

June 5, 2018

Mr. Rob Gramlich
Founder and President
Grid Strategies LLC
9207 Kirkdale Road
Bethesda, MD 20817

Dear Mr. Gramlich:

Thank you for appearing before the Subcommittee on Energy on Thursday, May 10, 2018, to testify at the hearing entitled “Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives.”

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, June 19, 2018. Your responses should be mailed to Kelly Collins, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Kelly.Collins@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment
The Honorable Fred Upton

1. Are Non-Transmission Alternatives such as energy storage, DER, and smart technologies receiving adequate consideration from transmission-owning utilities? Do incentives exist that would otherwise discourage utilities from adopting cheaper alternatives that would reduce costs for customers?

The incentives of transmission owners regulated under cost-of-service regulation with formula rates is to put more capital into the rate base and collect the return. This can be beneficial in cases where new transmission lines are needed and where there are not viable alternatives. That tends to be the case with accessing major remote renewable energy areas or to address persistent large regional or inter-regional congestion, where more transmission is generally needed. In some cases such as with MISO’s Multi-Value Projects, each of these multiple types of value were considered together, yielding $12 billion to $53 billion in net benefits, or between $250 and $1,000 for each person currently served by MISO, as I explained in my written testimony.

However there are many other situations where new transmission is not needed, or there are viable alternatives that are cheaper. Normally with cost-of-service regulation, such as that performed by state public utility regulatory commissions, there is an assessment of need and consideration of alternatives prior to granting the utility the right to construct the facility and charge customers. FERC does not do that with transmission. Instead, utilities build transmission and file informational filings to FERC. There is not a process to consider alternatives. There are many situations where even technologies that are clearly part of the transmission system, that attach to the wires or help manage flows on the wires more efficiently, are being overlooked. Dynamic Line Ratings, power flow control, network topology optimization, and some applications of energy storage fit in this category as technologies clearly serving only a transmission function and should be considered as alternative transmission options.

There are also claims by many parties that distributed resources such as those at the end-users’ locations behind the meter should be incorporated as non-wires alternatives and incorporated into transmission rates. FERC has the difficult job of determining whether those resources should be treated differently than generation, since both are serving other functions though they can reduce congestion or serve as an alternative to transmission to manage a contingency. To some extent, there is an incentive in energy markets for some of these options because locational prices signal to generation, DERs, and demand response to respond, both in the short and long run, when congestion causes high prices in an area. FERC will need to draw a line between what qualifies as transmission facilities and what does not.

2. There’s been some concern that utilities have an incentive to undertake large-scale transmission projects that aren’t necessary for reliability, or to forgo lower cost alternatives that would avoid building new lines. What changes could be made to reduce this incentive so we can avoid making large investments in transmission when cheaper alternatives are available?
I recommend three changes that FERC and its Congressional oversight committees can promote:

1) Change the incentive:
   a. Entertain utility filings under section 205 of the Federal Power Act to modify rate design to provide the transmission owner with an incentive to reduce congestion. Other countries have promising models that could be used. FERC has not yet expressed any openness to entertaining such proposals, though I am optimistic that the current set of Commissioners are interested in promoting innovation, especially in areas such as this one that can increase system reliability and resilience.
   b. Review incentive policy generally. As I explained in my written testimony, addressing incentives (other than return on equity for new lines) was never implemented by FERC after the Energy Policy Act of 2005, and is an important piece of unfinished business.

2) Improve planning. FERC should provide planning guidance to regional transmission planners about the use of advanced technologies to solve transmission needs. For example, RTOs and ISOs have planning protocols for market efficiency, yet none of them have a clear means for advanced grid utilization technologies to be considered.

3) Informally promote the consideration of all options and share best practices. Many of these options are new, and new technologies in regulated sectors generally have a hard time breaking in unless the regulator expresses interest in supporting them. This need not require “picking winners,” only allowing new entrants into the contest and clarifying how rules and standards apply to them.
The Honorable Richard Hudson

1. On April 19, FERC issued a new rule (Order No. 845) concerning revisions to the interconnection process for large generators which are over 20 MWs. The intent of this rule is to reduce the backlog of interconnection queue requests... Do you believe that this new interconnection rule will alleviate these backlogs?

I believe FERC Order 845 will significantly improve generator interconnection queue problems. As FERC concluded, “the reforms adopted in this Final Rule will help improve the efficiency of processing interconnection requests for both transmission providers and interconnection customers, maintain reliability, balance the needs of interconnection customers and transmission owners, and remove barriers to resource development.”

However, by itself, no interconnection policy can really solve the problem. There must also be a change to transmission planning to sufficiently incorporate future growth in and locations of new location-constrained generation. For example, there is solid information on where renewable resource areas are, and sufficient certainty based on relative economics (even ignoring clean energy or climate policies), that certain resource areas will be developed. Yet transmission planning operates in a vacuum, separate and independent from generation development and interconnection queues. Queue challenges have been avoided where transmission planning explicitly incorporated likely locations of new generation development. California and Texas have done this better than other regions, and MISO's Multi-Value Projects are a good example of such a process. When transmission planning fails to account for the amount and locations of future generation development, then large "network upgrade costs" get assigned to individual generators which are like charging the next car on a highway the cost of a lane expansion, or the next home in a subdivision the cost of the new road. Placing that burden on the next generator will inevitably cause that generator to drop out of the queue or change its plans, causing frustration for the transmission provider and generators alike.

2. How would modifications made by interconnection customers affect the interconnection studies of later-queued requests?

When there is a large network upgrade cost assignment at stake, which is the case when transmission planning fails to account for the amount a locations of new generation development, then each generator faced with such a charge will have a strong incentive to modify their plans in various ways to avoid or reduce the charge. FERC's Order No. 845 accepted some but not all of the recommendations by generators to improve the process. Yet the problem will not be fully solved until transmission planning and generation interconnection processes are better coordinated.