AMERICAN ENERGY SECURITY AND INNOVATION: GRID RELIABILITY CHALLENGES IN A SHIFTING ENERGY RESOURCE LANDSCAPE

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

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SUBMITTED MATERIAL

AMERICAN ENERGY SECURITY AND INNOVATION: GRID RELIABILITY CHALLENGES IN A SHIFTING ENERGY RESOURCE LANDSCAPE

THURSDAY, MAY 9, 2013

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

The subcommittee met, pursuant to call, at 9:05 a.m., in room 2123, Rayburn House Office Building, Hon. Ed Whitfield (chairman of the subcommittee) presiding.

Present: Representatives Whitfield, Hall, Shimkus, Pitts, Burgess, Latta, Cassidy, Olson, McKinley, Gardner, Pompeo, Kinzinger, Griffith, Barton, Upton (ex officio), Rush, McNerney, Tonko, Green, Capps, Barrow, Christensen, Castor, and Waxman (ex officio).

Staff Present: Nick Abraham, Legislative Clerk; Charlotte Baker, Press Secretary; Sean Bonyun, Communications Director; Matt Bravo, Professional Staff Member; Allison Busbee, Policy Coordinator, Energy & Power; Patrick Currier, Counsel, Energy & Power; Tom Hassenboehler, Chief Counsel, Energy & Power; Jason Knox, Counsel, Energy & Power; Mary Neumayr, Senior Energy Counsel; Tom Wilbur, Digital Media Advisor; Jeff Baran, Minority Senior Counsel; Kristina Friedman, Minority EPA Detailee; Caitlin Haberman, Minority Policy Analyst.

OPENING STATEMENT OF HON. ED WHITFIELD, A REPRESENTATIVE IN CONGRESS FROM THE COMMONWEALTH OF KENTUCKY

Mr. WHITFIELD. The hearing will come to order.

I certainly want to thank the panel of witnesses for being with us today. All of you are experts in your field, and we value your testimony, and certainly I will be introducing each one of you individually as soon as we finish our opening statements, but the hearing this morning is entitled “American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape.”

Today’s discussion builds on earlier hearings that address the challenges posed by changes in the Nation’s electricity generation portfolio. The proportion of electricity we get from coal, natural gas, nuclear, hydroelectric and non-hydro renewables has remained relatively constant over the last several decades. However, a shift is occurring, and what is alarming is how fast the mix has changed during the past few years. And it is this rapid transition that presents a number of pressing concerns that must be addressed in order to ensure a reliable and affordable electricity supply.

Most significantly, we are seeing a sharp drop in coal use and its replacement with natural gas. Part of this is due to market forces, namely the increased supply and relatively low price of domestic natural gas, but also part is the result of policy decisions made in Washington, particularly EPA's regulatory bias against coal.

Policy decisions are also behind the increased use of intermittent renewable resources, such as wind and solar power, especially the generous federal tax breaks and subsidies that favor them, as well as state level renewable electricity mandates. There certainly is room for debate of the merits of these policies and decisions and their impacts on electricity consumers and the American economy.

I for one am opposed to EPA's regulatory onslaught and will continue to oppose anti-coal rules because, like the President, I agree that we need all of the above, even though I think he wants to omit coal. But the point of this hearing is that these changes to the generation mix are occurring, and it is important that we think through what must be done to ensure that the lights stay on and that electric bills are affordable in the years ahead.

For example, the increased use of natural gas to provide electricity cannot go smoothly unless we have the pipeline capacity to carry it from where it is produced to the many new natural gas-fired power plants that are being built. We will need new natural gas pipelines as well as storage facilities to be constructed. However, we don't have a lot of time to build them, given the reliability challenges we face today, and we have already witnessed this scenario in areas like New England.

In addition, the federal-state policies that have given a boost to intermittent power sources could easily backfire if we don't address the difficulties of integrating these intermittent sources into the electric grid and the additional cost that that requires. Homeowners and businesses need electricity, whether or not the sun is shining or the wind is blowing, and the supply at any moment must meet the demand. This is nearly impossible to do with intermittent renewables that are not readily and reliably available.

I might also add that the long-term subsidization of certain generation sources, such as wind, can impair reliability and drive up electricity prices and increase integration costs. The wind PTPC was extended the end of last year, much to the disappointment of many of us. That extension alone is expected to cost over $12 billion over the next 10 years. And then, as many of you know, in January, EPA even made a decision in a ruling to exempt from the Clean Air Act emissions from generators that are used to back up wind power, and I recall that when we had our three forums on the Clean Air Act, many people said, well, you are out to destroy the Clean Air Act. We were not exempting anything from the Clean Air Act. We were simply having discussions with local regulators of the impact of the Clean Air Act and yet here EPA is exempting from the Clean Air Act backup generators for the wind—wind power.

The electric sector is changing, but one thing that remains constant is that homeowners, small business owners, manufacturers and others need reliable and affordable electricity. If we are going to be competitive in the global marketplace, we must do everything possible to ensure affordable and abundant electricity.

With that, at this time, I would like to recognize the distinguished gentleman from Illinois, Mr. Rush, for 5 minutes.

[The prepared statement of Mr. Whitfield follows:]

PREPARED STATEMENT OF HON. ED WHITFIELD

This hearing is entitled "American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape." Today's discussion builds on earlier hearings that addressed the challenges posed by changes in the nation's electricity generation portfolio.

The proportion of electricity we get from coal, natural gas, nuclear, hydroelectric, and non-hydro renewables has remained relatively constant over the last several decades. However, a shift is occurring and what is alarming is how fast the mix has changed during the past few years. And it is this rapid transition that presents a number of pressing concerns that must be addressed in order to ensure a reliable and affordable electricity supply.

Most significantly, we are seeing a sharp drop in coal use and its replacement with natural gas. Part of this is due to market forces, namely the increased supply and relatively low price of domestic natural gas. But part is also the result of policy decisions made in Washington, particularly EPA's regulatory attack on coal.

Policy decisions are also behind the increase in intermittent renewable resources such as wind and solar power, especially the generous federal tax breaks and subsidies that favor them as well as state-level renewable electricity mandates.

There certainly is room for debate over the merits of these policy decisions and their impacts on electricity consumers and the American economy. I for one strongly oppose EPA's regulatory onslaught and will continue to fight against these anti-coal rules. But the point of this hearing is that these changes to the generation mix are occurring, and it is important that we think through what must be done to ensure that the lights stay on and that electric bills are affordable in the years ahead.

For example, the increased use of natural gas to produce electricity cannot go smoothly unless we have the pipeline capacity to carry it from where it is produced to the many new natural gas-fired power plants that are being built. We will need new natural gas pipelines as well as storage facilities to be constructed. However, we don't have a lot of time to build them given the reliability challenges we face today and we have already witnessed this scenario in areas like New England. And I might add that although Keystone XL is an oil pipeline and not directly relevant to this discussion about electricity, the fact that Keystone XL has been delayed for over four years by this administration is a warning sign that this administration is no friend of building new pipeline infrastructure to transport fossil energy.

In addition, the federal and state policies that have given a boost to wind and solar power could easily backfire if we don't address the difficulties of integrating these intermittent sources into the electric grid.

Homeowners and businesses need electricity whether or not the sun is shining or the wind is blowing, and the supply at any moment must match the demand. This is nearly impossible to do with intermittent renewables that are not readily available.

I might also add that the long-term subsidization of certain generation sources, such as wind, can impair reliability and drive up electricity prices. The Wind PTC was extended at the end of last year much to the disappointment of many of us. That extension alone is expected to cost over $12 Billion dollars over the next 10 years. To put that in perspective, $12 billion is more than 10% of the entire $90 billion dollar sequester. In fact, $12 billion is six times more than the cost of the president's own proposal to create a $2 billion dollar Advanced Energy Trust Fund over the next decade. And what will the American taxpayer receive in return for subsidizing the wind industry for another 10 years? More expensive and less reliable energy.

The electric sector is changing, but one thing that remains constant is that homeowners, small business owners, manufacturers and others still need reliable and affordable electricity. I look forward to learning from our witnesses as to how best to accommodate the changes that are underway.

# # #

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, for holding today's hearing on, "Grid Reliability Challenges in a Shifting Energy Resource Landscape." Mr. Chairman, my question is, can we just come up with an acronym for all these words, this long title?

As the title of this hearing suggests, the country is indeed in a period of transition in an area of electricity generation away from some of the older, dirtier carbon-intensive coal-fired power plants and towards a heavy reliance on natural gas and renewable source of energy, including wind and solar and hydropower to generate electricity.

Twenty years ago, Mr. Chairman, coal accounted for over 50 percent of all power generation in this Nation while natural gas was responsible for less than 15 percent of electric generation. Today, Iowa, due to a combination of technological advancement in producing renewable energy, State and Federal incentives, environmental policies and market-based realities, the U.S. power supply is much more diversified with 37 percent of electricity generation coming from coal, 30 percent coming from natural gas, 19 percent from nuclear and 12 percent from renewable sources, including hydropower.

Mr. Chairman, this diversification of the Nation's power supply is a sign of the times as we move toward the 21st Century model, which does not rely too heavily on any single carbon-intensive energy source. Instead, by moving forward and diversifying our electric power supply to include more natural gas and clear renewable forms of energy, the U.S. is leading all advanced nations in decreasing our carbon emissions while also providing the energy necessary to provide for the needs of the American consumers and America's businesses.

According to the EIA in 2012, U.S. energy-related combustion emissions declined 3.7 percent to 1994 levels as a result of slow economic growth, the accelerating use of renewable energy sources and the transition from coal to natural gas. So, Mr. Chairman, while this reduction in carbon emissions is commendable, there is still a whole lot more that we have to do, more work that needs to be done. U.S. energy related carbon emissions is currently 5 percent above 1990 levels, and without additional policies, the EIA predicts that carbon pollution will continue to grow by 7.5 percent between 2012 and 2040.

President Obama has pledged to cut carbon emissions by 17 percent between 2005 levels—below 2005 levels by 2020 in order to help combat the devastating effect of climate change that we have been experiencing much too frequently. And in order to do so, we must continue to integrate renewable forms of energy into the electric power supply. Of course, as we continue to integrate renewable sources of anything into the power grid, natural gas will play a larger role in helping to avoid possible reliability issues.

Additionally, Mr. Chairman, we must encourage and promote the development of advanced technologies and best practices to help integrate renewable energy sources into the grid while maintaining reliability. We must ensure that FERC has the tools and the capability to remove barriers to integration.

Mr. Chairman, order 764 IRERs, which is the Integration of Reliable Energy Resources, which was finalized in June of 2012, is a clear example of FERC's ability to integrate renewable power into the grid while also helping to ensure that American families and American businesses have access to reliable and affordable energy.

Mr. Chairman, we must continue on this path of diversifying our Nation's power supply with cleaner, renewable sources of energy and while also making sure that FERC can and that the relevant agencies can and have the authority and the capabilities to keep America's lights on.

Thank you, and I yield back.

Mr. WHITFIELD. Gentleman's time has expired.

At this time, I recognize the gentleman from Michigan, Mr. Upton, for 5 minutes.

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

Mr. UPTON. Well, good morning. Today we are going to examine two key emerging issues facing the reliability of the Nation's electric grid, gas and electric convergence challenges and the integration of intermittent renewable energy resources.

As we have witnessed over the last couple of years, the Nation's electric generation portfolio is undergoing a dramatic shift, in part spurred by abundant and low-cost natural gas but also driven by environmental regs from the EPA that are forcing thousands of megawatts of coal-fired base load power to retire. This committee is dedicated to ensure the continued availability of affordable and reliable power to American homes and businesses, all the while protecting jobs in this rapidly changing energy landscape.

The shale gas revolution that we are witnessing today clearly presents enormous economic benefits for the country, and it is going to be an important driver of our economic growth moving forward. It is also going to set a path toward a better future for all of us, providing benefits across numerous sectors from manufacturing, residential to commercial uses.

Generating more electric power from natural gas has many benefits as well, especially given that domestic supplies are increasing and current prices are relatively low, but we are learning that there are also some real challenges to integrating more natural gas in the power sector.

Today's hearing also will focus on the increased integration of intermittent renewable resources, such as wind and solar, into the electric grid. As I have said on many times, many occasions, I support an open, all of the above, energy strategy, which includes renewable energy resources. However, we have got to be careful with regard to the cost of these resources and the taxpayer dollars that continue to subsidize them. We must also be mindful of the fact that incorporating an increased amount of renewables into the electric system presents operational challenges that in fact may impair with reliability. These resources are intermittent by their nature. The wind doesn't always blow, and the sun doesn't always shine.

Clearly, there is a role that these resources can play and should play, but to suggest that these sources alone can meet the power demands of the manufacturing technology and consumer sectors of the U.S. economy is a stretch of the imagination. Absent the continued use of our reliable and consistent base load power workhorses, like coal, nuclear, natural gas, the U.S. will not be able to compete globally.

America's newfound abundance of natural gas is a blessing, as are technological advances that make renewables more cost competitive and reliable. Both of these resources should and will play an important role in contributing to our energy needs, but we have got to take steps to properly and cost effectively integrate those resources into the energy and electric portfolio.

I look for forward to today's testimony, welcome our witnesses and would yield to other members on the Republican side. Seeing none, I yield back.

[The prepared statement of Mr. Upton follows:]

PREPARED STATEMENT OF HON. FRED UPTON

Today we examine two key emerging issues facing the reliability of the nation's electric grid—gas and electric convergence challenges and the integration of intermittent renewable energy resources.

As we have witnessed over just the last few years, the nation's electric generation portfolio is undergoing a dramatic shift, in part spurred by abundant and low cost natural gas, but also driven by environmental regulations from the EPA that are forcing thousands of megawatts of coal-fired baseload power to retire. This committee is dedicated to ensuring the continued availability of affordable and reliable power to American homes and businesses, all the while protecting jobs in this rapidly changing energy landscape.

The shale gas revolution we are witnessing clearly presents enormous economic benefits for the country that will be an important driver of our economic growth moving forward. It will set a path toward a better future for all of us, providing benefits across numerous sectors from manufacturing, residential, to commercial uses.

Generating more electric power from natural gas has many benefits as well, especially given that domestic supplies are increasing and current prices are relatively low. But we are learning that there are also some very real challenges to integrating more natural gas into the power sector.

Today's hearing also will focus on the increased integration of intermittent renewable resources, such as wind and solar, into the electric grid. As I have made clear on numerous occasions, I support an open, all-of-the-above energy strategy, which includes renewable energy resources. However, we must be mindful of the cost of these resources and the taxpayer dollars that continue to subsidize them.

We must also be mindful of the fact that incorporating an increasing amount of renewables into the electric system presents operational challenges that may impair grid reliability. These resources are intermittent by their nature—the wind doesn't always blow and the sun doesn't always shine. Clearly there is a role these resources can play but to suggest these sources alone can meet the power demands of the manufacturing, technology, and consumer sectors of the U.S. economy is a stretch of the imagination. Absent the continued use of our reliable and consistent baseload power work horses like coal, nuclear, and natural gas, the U.S. will not be able compete globally.

America's newfound abundance of natural gas is a blessing, as are technological advancements that make renewables more cost competitive and reliable. Both of these resources should—and will—play an important role in contributing to our energy needs. But we need to take steps to properly and cost-effectively integrate these resources into the electricity portfolio. I look forward to today's testimony, and learning about the best ideas for moving forward.

# # #

Mr. WHITFIELD. Gentleman yields back.

At this time, recognize the gentleman from California, Mr. Waxman, for 5 minutes.

OPENING STATEMENT OF HON. HENRY A. WAXMAN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF CALIFORNIA

Mr. WAXMAN. Thank you, Mr. Chairman.

Today, the subcommittee is holding its third hearing on America's evolving electricity generation portfolio, and there is no question that a significant transition is under way.

Renewable energy policies are paying off. We have doubled our capacity to generate renewable electricity from wind and solar in just 4 years. Cheap natural gas is also helping to transform our electricity sector. This market reality is causing some utilities to replace their oldest, dirtiest and least efficient coal plants with natural gas generation.

These are positive developments, but these changes also create challenges for our electric grid. The testimony from the prior hearings showed that these issues are manageable and that both regulators and grid operators are focused on them. Yet there has been no focus from the Republican Members on the bigger challenges posed by climate change, and while they are ignoring climate change, they seem to bemoan the transition that is occurring. While they call for a market based economy, they don't seem to like the fact that the market economy is driving natural gas to replace coal. They seem to want to use coal no matter what. Don't let the market decide it; let's let the coal people decide it. They offer no solutions, no ideas for cutting carbon pollution or deploying more clean energy generation. Instead, the only thing that seems to unite them is attacking EPA. They attack EPA's air quality standards and lament the loss of coal's market share.

There is a confused aspect to these hearings. Some Republican Members cannot seem to decide whether they like cheap natural gas or see it as a threat that must be overcome to protect the coal industry. They seem unsure whether they should be celebrating reduced carbon pollution or avoiding the issue all together. This confusion is not surprising because the subcommittee still hasn't examined why this transition in our energy sector must occur.

Climate change is the biggest energy challenge we face as a country. We can't have a meaningful discussion of the transition under way in the energy sector without understanding the threat of climate change. We have heard a lot lately about U.S. carbon dioxide emissions being at their lowest level in 20 years. The implication is no further action to address climate change is necessary, and that is simply not the case.

As a result of increased renewable energy generation, a shift from coal to natural gas generation and the economic recession, U.S. emissions from the energy sector have dropped in recent years, but U.S.—total U.S. emissions from all sources, not just the power sector, actually increased from 2009 to 2011. What matters most is whether U.S. emissions are on track to decline in the future by the amount needed to prevent dangerous climate change. No reputable expert believes this to be the case.

Scientists tell us that our emissions need to decline by at least 80 percent below 1990 levels by 2015 to avoid a dangerous level of warming. The latest projections by the Energy Information Administration show that U.S. carbon dioxide emissions from fossil fuel combustion actually will be 13 percent higher than 19 levels in 2040, the last year of the EIA's model. There is an enormous gulf between what these emissions will be without additional action and what they need to be to avert catastrophic warming.

Today's hearing continues this unfortunate and counterproductive trend. The majority appears to have called this hearing, in part, to invite attacks on renewable energy. If we are going to hear from opponents of renewable energy and critics of EPA's proposed standards to reduce carbon pollution from new power plants, we should hear from the scientists and technical experts who can explain why it is so important for the United States to reduce its carbon pollution. We should hear from witnesses who can inform the subcommittee about the dangers of manmade climate change and the closing window for effective action. The threat of climate change is not going to disappear if we pretend it doesn't exist. We need to start recognizing reality and crafting responsible solutions.

[The prepared statement of Mr. Waxman follows:]

PREPARED STATEMENT OF HON. HENRY A. WAXMAN

Today, the Subcommittee is holding its third hearing on America's evolving electricity generation portfolio. There is no question that a significant transition is underway.

Renewable energy policies are paying off. We have doubled our capacity to generate renewable electricity from wind and solar in just four years.

Cheap natural gas is also helping to transform our electricity sector. This market reality is causing some utilities to replace their oldest, dirtiest, and least efficient coal plants with natural gas generation.

These are positive developments. But these changes also create challenges for our electric grid. The testimony from the prior hearings showed that these issues are manageable and that both regulators and grid operators are focused on them.

Yet there has been no focus from the Republican members on the bigger challenges posed by climate change. They offer no solutions . no ideas for cutting carbon pollution or deploying more clean energy generation. Instead, they attack EPA's air quality standards and lament the loss of coal's market share.

There is a confused aspect to these hearings. Some Republican members cannot seem to decide whether they like cheap natural gas or see it as a threat that must be overcome to protect the coal industry. They seem unsure whether they should be celebrating reduced carbon pollution or avoiding the issue all together.

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The threat of climate change is not going to disappear if we pretend it doesn't exist. We need to start recognizing reality and crafting responsible solutions.

Mr. WHITFIELD. Gentleman yields back. At this time, I would like to introduce the members of the panel, and as I said in the beginning, we genuinely appreciate all of you being here, and we certainly value your input and thought on these important issues.

STATEMENTS OF GARY SYPOLT, CEO, DOMINION ENERGY, ON BEHALF OF INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; JOHN SHELK, PRESIDENT AND CEO, ELECTRIC POWER SUPPLY ASSOCIATION; PAUL CICIO, PRESIDENT, INDUSTRIAL ENERGY CONSUMERS OF AMERICA; DANIEL WEISS, SENIOR FELLOW AND DIRECTOR OF CLIMATE STRATEGY, CENTER FOR AMERICAN PROGRESS; ROBERT GRAMLICH, INTERIM CEO, AMERICAN WIND ENERGY ASSOCIATION; AND JONATHAN LESSER, PRESIDENT, CONTINENTAL ECONOMICS, INC.

Mr. WHITFIELD. First, we have Mr. Gary Sypolt, who is the CEO of Dominion Energy, who is going to be testifying on behalf of the Interstate Natural Gas Association of America.

We have Mr. John Shelk, who used to be a part of the Energy and Commerce Committee. I was going to say many, many years ago, but it wasn't that many years ago.

Mr. SHELK. Lincoln was the——

Mr. WHITFIELD. And John is the president and CEO of Electric Power Supply Association.

We have Mr. Paul Cicio, who is the president of the Industrial Energy Consumers of America. We have Mr. Daniel Weiss, who has testified here before, and he is the senior fellow and director of climate strategy for the Center for American Progress.

We have in Robert Gramlich, who is the interim CEO of the American Wind Energy Association.

And we have Dr. Jonathan Lesser, who is the president of Continental Economics, Incorporated.

So, once again, welcome to all of you. We look forward to your testimony. I will be recognizing each one of you and you will be given 5 minutes for an opening statement, and then, at the end, at the conclusion of that, we will have questions and answers.

So, Mr. Sypolt, you are recognized for 5 minutes.

STATEMENT OF GARY SYPOLT

Mr. SYPOLT. Chairman Whitfield, Ranking Member Rush, members of the subcommittee, good morning. My name is Gary Sypolt.

I am CEO of Dominion Energy. Headquartered in Richmond, Virginia, Dominion operates a broad portfolio of energy assets, including electric generation and transmission, natural gas transmission, storage and distribution. Dominion Energy, the segment of the company that I oversee, is focused on our natural gas assets.

Today I am testifying on behalf of the Interstate Natural Gas Association of America or INGAA. INGAA represents interstate pipeline, natural gas transmission pipeline operators in the U.S. and Canada. I am a member of the INGAA board and the chair of the board's task force on gas electric power reliability.

You are all aware of the shale gas revolution, the new opportunities that it has created for the U.S. economy and the rapid changes that have occurred as a result.

One of the principal areas in which this has occurred is in the use of natural gas as a fuel for electric power generation. There is no question that natural gas and natural gas pipelines can serve gas-fired electric power generators reliably. Questions about whether and to what extent natural gas is used to generate electricity will be resolved by the generators and by policymakers. If natural gas continues to be chosen as a fuel prepared generation, though, the pipeline industry is confident that it can reliably meet the needs of power customers, assuming that such customers contract for the appropriate level of pipeline services.

Concerns about natural gas electric power reliability vary by region and depend on several factors referenced by my written testimony. New England has attracted the greatest concern in recent years, but it is not the only region where this concern has been raised by grid operators and other stakeholders. The problem in New England is that wholesale electric market rules do not allow generators to recover the cost associated with ensuring electric reliability, and electric prices do not reflect these reliability costs.

While generators in New England are acting rationally based on current market rules, the end result may be a reduction in electric reliability and a greater risk of blackouts that could be very costly to the region.

The good news is that the interstate natural gas pipeline industry has a proven track record for building infrastructure in response to market demand. In my written testimony, you can see a map of the 12,000 miles of new pipelines placed in service over the last decade. If the market provides timely signals that it needs additional capacity, that is, in the form of firm contractual commitments for that capacity, the industry can add new pipeline capacity in a market responsive manner.

The key point here, pipelines are designed to meet the needs of shippers with firm contracts. Unlike electric utilities, pipelines typically are designed with little or no excess capacity. In other words, there is no reserve margin. This is why firm contracts for pipeline service are critical, and in fact, the FERC looks at a firm contractual commitment in deciding whether to approve a new pipeline in the first place; in other words, whether the pipeline meets the public convenience and necessity.

Restructuring of wholesale natural gas markets has been a remarkable success. As demonstrated by the robust pipeline expansion over the last decade, the natural gas model works. This success should not be undermined as policymakers examine how to achieve greater natural gas and electric power market coordination. Electric market rules must be reformed to value investments in reliability and to ensure the ability to recover such costs from those who benefit from reliable electricity. With such arrangements, necessary natural gas infrastructure can and will be built. Without such arrangements, the gas side risk, degradation of the quality of service for natural gas utilities and traditional gas pipeline customers who pay for reliable service, while on the electric side, there would be a greater risk if parts of the nation would experience more volatile power prices and increasing potential for blackouts.

Let me thank the subcommittee for the opportunity to testify today, and I will be happy to answer questions at the appropriate time. Thank you.

[The prepared statement of Mr. Sypolt follows:]

TESTIMONY OF
GARY L. SYPOLT
CHIEF EXECUTIVE OFFICER
DOMINION ENERGY

ON BEHALF OF
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON ENERGY AND COMMERCE
U.S. HOUSE OF REPRESENTATIVES

REGARDING
GRID RELIABILITY CHALLENGES IN A SHIFTING ENERGY RESOURCE LANDSCAPE

MAY 9, 2013

Good morning Chairman Whitfield, ranking member Rush and members of the Subcommittee on Energy and Power. My name is Gary L. Sypolt and I am the executive vice president of Dominion Resources Inc. and the Chief Executive Officer of Dominion Energy. I am appearing before you today in my capacity as the first vice chairman of the board of directors of the Interstate Natural Gas Association of America (INGAA) and as the chairman of the INGAA board task force on natural gas/electric power reliability.

Dominion, headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy. Dominion's strategy is to be a leading provider of electricity, natural gas and related services to customers primarily in the eastern region of the U.S. Dominion's portfolio of assets includes approximately 27,500 megawatts (MW) of generating capacity, 6,300 miles of electric transmission lines, 56,900 miles of electric distribution lines, 11,000 miles of natural gas transmission, gathering and storage pipeline and 21,800 miles of gas distribution pipeline, exclusive of service lines of two inches in diameter or less. Dominion also operates one of the nation's largest underground natural gas storage systems, with approximately 947 billion cubic feet (Bcf) of storage capacity, and serves nearly six million utility and retail energy customers in 15 states.

INGAA represents interstate natural gas transmission pipeline operators in the U.S. and Canada. Our 26 members account for virtually all of the major interstate natural gas transmission pipelines in North America and operate about 200,000 miles of transmission pipe in the U.S.

U.S. Interstate Natural Gas Transmission Pipelines: A Robust Infrastructure

Thank you for the opportunity to share INGAA's views on meeting natural gas and electric power challenges. As you know, the shale revolution and the newly realized abundance of domestic natural gas have created new opportunities for the U.S. and have prompted significant and rapid changes in our nation's energy economy. One of the principal areas in which this has occurred is in the use of natural gas as a fuel for electric power generation. Interstate natural gas pipelines are the critical link between natural gas suppliers and electric power generators and will play a major role in ensuring the ability to serve this growing market for natural gas.

INGAA and its member pipeline companies have been actively engaged on these questions from the start. We have participated actively in all seven of the Federal Energy Regulatory Commission technical conferences held to date. We have reached out to a wide range of the other stakeholders with an interest in this issue, including the grid operators, state regulators, the North American Electric Reliability Corporation, and groups representing electric generators, as well as other segments of the natural gas industry affected by these developments. In addition, when customers have requested, individual pipeline companies have offered natural gas transportation services tailored to the particular needs of electric power generators.

There is no question that natural gas and natural gas pipelines can serve gas-fired electric power generation reliably. Choices about the desired portfolio of technologies and fuels for electric power generation are up to the market, the electric power industry, regulators and policymakers. Still, if natural gas is chosen as a fuel for electric power generators, the pipeline industry is confident that it can reliably meet the needs of these customers assuming that they contract for the appropriate natural gas transportation services.

In fact, this is more properly viewed as an electric reliability issue. In particular, the pertinent question is whether the market rules and regulatory structures within a wholesale electric power market place an appropriate value (or price) on reliability such that there is an incentive to ensure the ability of a generator to operate reliably. This is a critical question no matter what option is chosen to ensure the reliability of an electric generator, i.e., contracted pipeline capacity, liquefied natural gas, coal, dual fuel capability or some other means.

Concerns about natural gas/electric power reliability vary by region and depend on several factors. These include the mix of generating technologies within a region, the electric generation reserve margin within a region, the availability of natural gas pipeline and storage capacity within a region, and the structure of the wholesale electric power market within a region[1] and the incentives created by that structure.

New England has attracted the greatest concern in recent years. This is because the region's reliance on natural gas-fired generation has grown significantly, while at the same time the rules in the restructured wholesale power market make it difficult for generators to recover the costs associated with procuring reliable natural gas service. Generators in restructured wholesale power markets cannot include fixed costs (such as the cost of a pipeline transportation contract) as part of their bids in the energy market and consequently are provided with little or no assurance that such costs otherwise can be recovered. Accordingly, generators in New England are making a rational economic choice when they choose not to sign up for firm pipeline

[1] Electric utilities may participate in a bilateral market in which utilities remain vertically integrated or an "organized" or restructured market in which an independent entity operates the transmission system and administers a bid-based power market.

transportation. Rather, generators predominantly rely on pipeline capacity acquired in the secondary market to meet their natural gas delivery needs. The problem is that secondary market pipeline capacity likely will not be available on cold peak winter days when the pipeline's firm customers, typically the local gas utilities, are using their full contractual entitlements. Other factors contributing to the concerns in New England include the fact that the region is at the end of the pipeline network, pipeline capacity in the region already is tight, and the region's growing dependence on natural gas for space heating as low-priced natural gas is winning the competition with other fuels. In short, it has the potential to be the perfect storm.

To be clear, generators in New England are acting rationally, based on current wholesale electric market rules. If anything is to blame in New England, it is the fact that these electric market rules *do not* allow generators to recover the costs associated with ensuring electric reliability, and electric prices do not reflect these reliability costs.

Still, it is a mistake to view these reliability concerns as only a New England issue. For example, there are concerns in the Midwest Independent System Operator (MISO) region given the anticipated level of retirements of coal-fired generation and the likelihood that natural gas generators will backfill this displaced capacity. As MISO Executive Vice President Clair Moeller testified at the March 19, 2013 hearing before this subcommittee, MISO estimates that about 11.5 gigawatts (GW) of coal-fired generation could need to be replaced to comply with environmental regulations.[2] MISO is using this time to identify potential impediments to integrating this much gas-fired generation and to plan accordingly. There also could be concerns about electric reliability in regions, such as the Pacific Northwest or the southwest, that have made heavy commitments to variable renewable generation and where gas-fired generators will be expected to backup these renewable generators.

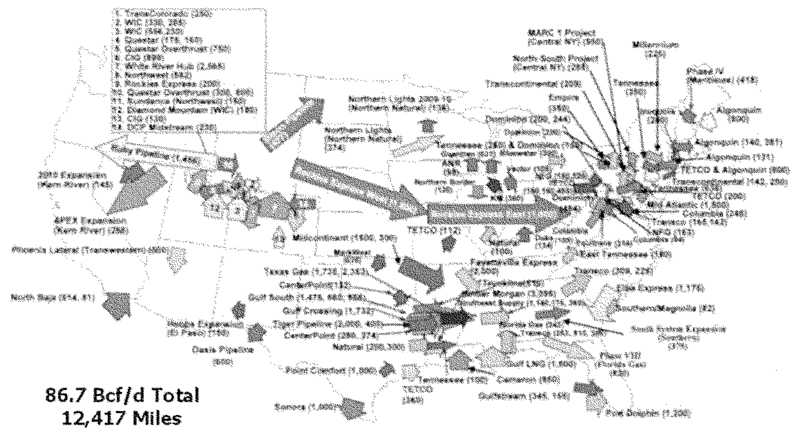
The good news is that the interstate natural gas pipeline industry has a proven track record of building infrastructure in response to market demand. If the market signals that it needs additional capacity (in the form of firm contractual commitments for the capacity) the industry

[2] Testimony of Clair J. Moeller, Executive Vice President of Transmission & Technology of the Midwest Independent Transmission System Operator, Inc. (MISO), Before the House Subcommittee on Energy and Power of the Committee on Energy and Commerce, United States House of Representatives, March 19, 2013, "MISO's 2013 1st Quarter Survey: Impacts on Coal-Fired Generation Capacity (GW)." The Brattle Group also projects 11-16 GW in coal retirements in the MISO region by 2016. Metin Celebi, "U.S. Coal Plant Retirements: Outlook and Implications," The Brattle Group, January 24, 2013. Affected power plants will have to comply with the Environmental Protection Agency's (EPA's) Mercury and Air Toxins (MATS) Rule for Power Plants by April 16, 2015, with the possibility for a one or two year extension on a case-by-case basis.

can add new pipeline capacity in a timely, market-responsive manner. Between January 2003 and March 2013, pipelines placed into service more than 12,000 miles of new interstate pipeline capacity.[3] By comparison, only 1,113 miles of high volatage interstate transmission lines were built between January 2000 and September 2011. There is no reason to doubt the natural gas pipeline industry's ability to build the capacity needed to keep pace with market demand – whether it is a "supply push" pipeline that will access new shale gas production or a "demand pull" pipeline to deliver natural gas to growing consumer markets.

Proven Track Record of Building Pipeline Infrastructure
Over 12,000 Miles in Ten Years

Major Pipeline Projects In-Service: January 2003 – March 2013



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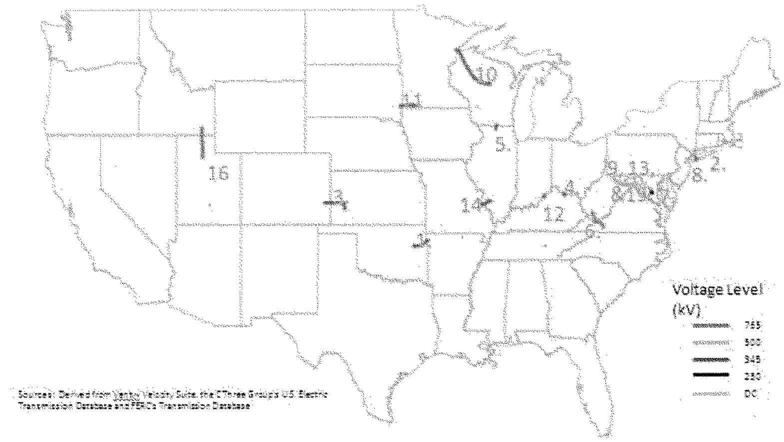
[3] Federal Energy Regulatory Commission, Office of Energy Projects.

High Volatage Interstate Transmission Lines Built
January 2000 – September 2011
1,113 Total Miles



While there are parallels between the natural gas and electric power industries, there also are significant differences in the physics of moving natural gas and electricity, how the industries are regulated and the commercial models for doing business. In thinking about natural gas and electric power market coordination, it is important to appreciate these differences. The key features of the natural gas model and, in particular, interstate natural gas pipelines include the following:

First, pipelines are "open access" transporters and storage providers. That means that pipelines must serve all customers (or shippers) with no undue discrimination. Pipelines transport natural gas for local gas utilities, marketers, industrial users, producers and power generators. These customers typically purchase natural gas transportation under the same rate schedule and under the same terms and conditions of service. Accordingly, pipelines cannot "unduly discriminate" to favor electric generators over other customers.

Second, pipelines provide storage and transportation on a fully unbundled basis. Pipelines no longer buy and sell the natural gas commodity; instead, pipelines are transporters only, much like freight railroads. The customer must purchase and deliver its own natural gas to the pipeline. Pipelines then transport that gas to the customer's delivery point.

Third, pipelines compete for market opportunities. Pipelines do not have dedicated service territories. Often more than one pipeline competes to serve a new or increased load. The Federal Energy Regulatory Commission (FERC) may authorize the construction of a pipeline project, but the market ultimately picks the winners and the losers.

Fourth, a fundamental principle of FERC rate regulation is that only the shippers that benefit from a new or expanded pipeline should pay for it.[4] FERC calls this "incremental pricing." Unlike the electric industry, pipelines cannot socialize the costs of expanding the system for one customer, such as a generator, across all customers.

Fifth, pipelines are designed to meet the needs of shippers with firm contracts. Unlike electric utilities, pipelines typically are designed with little or no excess capacity (i.e., there is no reserve margin). Firm shippers pay fixed charges in order to reserve capacity on the pipeline. In exchange, these customers receive the highest scheduling priority.

Sixth, there is a secondary market for natural gas pipeline capacity. When firm shippers do not need to use their full contracted amounts, they may resell their capacity to other shippers (also known as capacity release). Or, if a firm shipper does not either use its capacity or release that capacity to another shipper, the pipeline may sell the capacity as interruptible transportation. During periods of heavy natural gas demand, however, when firm shippers are using their full contractual entitlements, there may be no pipeline capacity available in the secondary market, in which case shippers without firm capacity may be unable to arrange the delivery of natural gas.

Seventh, customers ensure reliability individually by taking responsibility for a portfolio of natural gas services that meets their needs. A pipeline, for example, cannot dictate that any customer contract for firm pipeline transportation.

Eighth, interstate pipeline service is not curtailed based on end-use priorities. For example, a pipeline must serve a toy factory that holds firm pipeline transportation over an electric generator that holds only interruptible transportation.

[4] FERC policy permits such cost to be socialized (or rolled-in) only when the new pipeline will reduce the gas pipeline transportation rates for all shippers or when the proponent can demonstrate that the expansion benefits existing customers, such as an expansion that improves system reliability or flexibility.

The restructuring of wholesale natural gas markets has been a remarkable success. The goal of Congress in decontrolling natural gas at the wellhead was for consumers to reap the benefits of competition. FERC's restructuring of interstate natural gas pipelines in the wake of wellhead decontrol greatly facilitated the achievement of this goal. As demonstrated by pipelines' robust infrastructure development over the past decade, illustrated above, the natural gas model works. This success should not be undermined as policymakers examine how to achieve greater natural gas and electric power market coordination.

While natural gas pipelines are willing to consider changes to improve the efficiency of natural gas markets and natural gas transportation, fundamental changes must occur in the restructured wholesale power markets. INGAA agrees that improving communications between the gas and electric industries and additional scheduling opportunities should be considered. Yet, if a region does not have adequate natural gas infrastructure to meet growing reliance on gas-fired generation, electric reliability will not be guaranteed by additional communication or capacity scheduling opportunities. These enhancements will not create new pipeline capacity.

Pipelines recognize that electric power generation is the largest and fastest growing market for natural gas, and we are excited to serve this market. Still, generators are not the only ones that rely on interstate pipelines. In fact, natural gas utilities, producer/marketers and industrial customers are often the entities that contract for firm pipeline service. These customers pay for reliability, and they are entitled to receive it. Such firm customers have reason to be concerned if the quality of their service is threatened by non-firm customers that have not contracted for appropriate services. This is a particular concern when generators take unauthorized volumes from a pipeline in order to meet their commitments to generate electricity.

This disconnect between the incentives created by wholesale power market rules and the need for commitments to ensure the availability of pipeline capacity has been widely noted, including by two members of the FERC. In testimony before this subcommittee on March 19, Commissioner Cheryl LaFleur stated that "there is often a disconnect between market price signals and the associated infrastructure that is necessary to support the gas resources in those markets, especially on a regional basis."[5] She noted that the current legal and regulatory system for certifying pipelines works extremely well and pointed out some of the problems of electric generators relying solely on interruptible transportation or released pipeline capacity.

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[5] Summary Testimony of Commissioner Cheryl A. LaFleur, Federal Energy Regulatory Commission, Before the House Subcommittee on Energy and Power of the Committee on Energy and Commerce, United States House of Representatives, March 19, 2013 at 3.

In addition, at an April 30, 2013 public meeting, Commissioner Tony Clark stated that "the breakdown that we seem to be having [appears] to be on the electric side of the equation, especially in these regions that have, for better or worse, restructured the retail side of their operation."[6] Commissioner Clark highlighted that one factor in determining the immediacy of concerns related to integrating the gas and electric industries is whether a region is in a retail restructured electric market versus a state commission-regulated electric market where generators can recover of the cost of holding firm pipeline services.

Based on the discussions at the FERC technical conferences on natural gas and electric power market coordination, it appears that electric generators that remain within vertically integrated utilities typically contract for the portfolio of pipeline and storage services needed to ensure the reliability.[7] The fact that these generators have the ability to both subscribe for the appropriate level of firm transportation and storage services and to support infrastructure expansions, when necessary, further reinforces the point that the solution to concerns about ensuring the reliability of natural gas-fired generation lies in the design of organized wholesale power markets.

There is urgency to addressing these issues, particularly in New England. In his March 19 testimony before this subcommittee, ISO-New England President and Chief Executive Officer Gordon van Welie stated:

> In the past decade, natural gas has become the predominant fuel used to produce electricity in New England; however, the limitations of the current market design and the consequent inadequate fuel arrangements by natural-gas and oil-fired generation have led to serious reliability threats to the bulk power system.[8]

This point was reinforced by the ISO New England Winter Operations Summary: January-February 2013, which referred to "persistent reliability concerns, which are most acute during extended cold-weather periods when natural gas demand by local distribution companies [local

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[6] Kate Winston, "Most gas-power coordination woes due to electricity: FERC's Clark," *Gas Daily*, May 1, 2013 at 5.

[7] While this most commonly is the case with generators in bilateral markets, it also occurs in cases in which regulated generation is constructed in restructured markets.

[8] Testimony of Gordon van Welie, President and Chief Executive Officer, ISO New England, Before the House Subcommittee on Energy and Power of the Committee on Energy and Commerce, United States House of Representatives, March 19, 2013 at 1.

gas utilities] is high."[9] The same report stated that "[t]he key point from this winter is that the region needs to develop immediate solutions to avert serious threats to system reliability next winter."[10]

Without a doubt, there will be costs associated with ensuring reliability through the combination of investment in new natural gas pipeline capacity and other means. Still, this must be balanced against the cost of failing to ensure reliability. For example, a January 2013 report to ISO New England examined the benefits of reducing the probability, frequency or duration of bulk power system interruptions. As a benchmark, the report cited estimates that the 2003 Northeast blackout, which caused wide-spread electricity outages in New England for two days, cost the region between $4 billion and $10 billion (in $2003). The same report estimated that a future power outage in New England could cost anywhere from $500 million for a momentary outage to over $6 billion for an eight hour outage.[11] In the face of such costs, the ISO has proposed a number of short-term and long-term market and operational solutions to increase reliability and efficiency, including changes to electric market pricing incentives, increasing use of dual-fuel capacity and in-region LNG storage, and new interstate natural gas pipeline capacity.

The interstate natural gas pipeline sector enjoys a favorable legal and regulatory framework for the approval of new infrastructure. Even with this regulatory framework, it typically takes three to four years from pipeline project inception to "steel in the ground" that is ready to transport natural gas. Moreover, the law requires FERC to find that there is a need for a pipeline before construction can be authorized. This most typically is done based on a demonstration by the pipeline company that is has long-term firm contracts for the proposed project. While we respect the stakeholder processes within the ISOs and the challenging nature of these issues, electric reliability cannot be addressed at a snail's pace. The fundamental questions about reforming wholesale power market rules to value reliability must be resolved soon. If this does not happen, there is a significant risk that new pipeline capacity and other solutions needed to ensure reliability will not be ready when needed.

The availability of natural gas for power generation is one of the many benefits that the nation is realizing from the shale revolution and the resulting abundance of natural gas. This has been a

[9] ISO New England, *Winter Operations Summary: January – February 2013*, Draft – For Review and Discussion, February 27, 2013.
[10] Id.
[11] Memo from Paul Hibbard, Analysis Group to ISO-New England, "Information from the Literature on the Potential Value of Measures to Improve System Reliability," January 24, 2013 at 3.

remarkable change that has brought our nation significant economic, environmental and strategic benefits. For example, a July 2012 Bank of America Merrill Lynch study estimated that lower utility costs, resulting from lower natural gas prices, have saved U.S. companies and consumers an average of $566 million *a day*. At the same time, due largely to the increased use of natural gas for electric power generation, U.S. CO_2 emissions have been reduced to their lowest level since 1992. And the resurgence of domestic natural gas and crude oil production has greatly improved our energy security.

To realize these benefits fully, however, we must address the obstacles that in some markets may undermine the ability to construct the natural gas infrastructure needed to serve the growing electric generation market. Market rules must be reformed to value investments in reliability and to ensure the ability to recover such costs from those who benefit from reliable electricity. With such arrangements, the necessary natural gas infrastructure can and will be built. Without such arrangements, there will be a much greater risk that parts of the nation will experience increasing blackouts, volatile power prices and degradation of the quality of service for natural gas utilities and other traditional natural gas pipeline customers.

Let me thank the Subcommittee, once again, for permitting me the opportunity to testify today. I would be happy to answer your questions.

Summary of Testimony for
Gary L. Sypolt

- INGAA represents interstate natural gas transmission pipeline operators in the U.S. and Canada.
- The shale revolution and the newly realized abundance of domestic natural gas have created new opportunities for the U.S. and have prompted significant and rapid changes in our nation's energy economy. One of the principal areas in which this has occurred is in the use of natural gas as a fuel for electric power generation.
- There is no question that natural gas and natural gas pipelines can serve gas-fired electric power generation reliably. If natural gas is chosen as a fuel for electric power generators, the pipeline industry is confident that it can reliably meet the needs of these customers assuming that they contract for the appropriate natural gas transportation services.
- Concerns about natural gas/electric power reliability vary by region and depend on several factors. New England has attracted the greatest concern in recent years.
- The problem in New England is that wholesale electric market rules do not allow generators to recover the costs associated with ensuring electric reliability, and electric prices do not reflect these reliability costs. While generators in New England are acting rationally based on current market rules, the end result may be a reduction in electric reliability and a greater risk of blackouts that could be very costly to the region's economy.
- The good news is that the interstate natural gas pipeline industry has a proven track record of building infrastructure in response to market demand. If the market provides timely signals that it needs additional capacity (in the form of firm contractual commitments for the capacity), the industry can add new pipeline capacity in a market-responsive manner.
- Pipelines are designed to meet the needs of shippers with firm contracts. Unlike electric utilities, pipelines typically are designed with little or no excess capacity (i.e., there is no reserve margin).
- The restructuring of wholesale natural gas markets has been a remarkable success. As demonstrated by pipelines' robust infrastructure development over the past decade, the natural gas model works. This success should not be undermined as policymakers examine how to achieve greater natural gas and electric power market coordination.
- Market rules must be reformed to value investments in reliability and to ensure the ability to recover such costs from those who benefit from reliable electricity. With such arrangements, the necessary natural gas infrastructure can and will be built. Without such arrangements, there will be a much greater risk that parts of the nation will experience increasing blackouts, volatile power prices and degradation of the quality of service for natural gas utilities and other traditional natural gas pipeline customers.

Mr. WHITFIELD. Thanks, Mr. Sypolt.

Mr. Shelk, you are recognized for 5 minutes.

STATEMENT OF JOHN SHELK

Mr. SHELK. Thank you. Good morning, Chairman Whitfield, Ranking Member Rush and members of the subcommittee. As a former committee counsel, it is a particular honor to be back today. As noted, I am here on behalf of the Electric Power Supply Association. EPSA is the national trade association for competitive wholesale electricity suppliers. Our members supply electricity across the country with a particular emphasis on states and regions with independent grid operators. This means their major sources of electricity from Maine down here to Virginia and states across from the Mid-Atlantic to my home State of Illinois, and particularly in Texas and California.

The subcommittee is wise to focus on the challenges already discussed. Today's headlines focus on natural gas, but we should also be asking ourselves, what will be the headlines of tomorrow? What will be the game changers next year or over the next decade? EPSA believes that competitive electricity markets are best able to adapt to these changes, and our written testimony focuses on three particular challenges that I will summarize now: electric-gas coordination; a new topic that Chairman Whitfield referred to called demand response; and finally, variable resources.

First on electric gas coordination, I think it is important to point out that gas-fired generators already have as much interest and financial incentive as anyone in making sure gas could be delivered to their power plants to generate electricity. This is because, in competitive markets such as New England and Texas and elsewhere, these plants do not earn revenue from generating electricity unless they can get gas to run. They do not have a regulated rate base.

The important message we would leave with you is that today and going forward, these plants procure fuel many ways, only one of which is through a firm long-term transportation arrangement that the pipelines just referred to. Instead, power plants today serve consumers of electricity reliably as well as cost effectively many other options: packaged products from producers and gas marketers with packages that include both the gas supply and the transportation, interruptible service, capacity release, and delivery from gas distribution utilities. These generators need continued access to this full suite of options to tailor their gas supply arrangements to the type of plant, location and market being served. These options generally work well, as evidenced by the substantial increased utilization of gas-fired power plants that many of you have already referred to.

We are in agreement with INGAA that electric gas issues vary by region, and regional solutions are best. And FERC is acting accordingly. FERC and grid operators are vigilant, as you heard at the hearing last month. New England is appropriately seen as the region with the most pressing challenges, and our regional trade association there is co-chairing the regional effort, looking at these issues in depth.

FERC recently acted to improve the scheduling times for gas and electricity, which will help, and active consideration is being given at the state level to possibly encouraging gas utilities to procure more firm pipeline capacity, but the regional market is also looking to actively consider changes to electric market rules.

The second topic I would like to mention is one not often considered here but should be, and that is called demand response. Demand Response entails programs in which most energy consumers, particularly residential and commercial customers, pay others, primarily industrial customers, for them to use less electricity. In what is called order 745, FERC went beyond its authority, in our view and the view of the other national electricity associations, to pay this demand response as if it were generation, and we and those other associations are presently in the Federal court here in the District of Columbia and the Court of Appeals challenging that order.

No amount of demand response can substitute for the substantial supplies of actual megawatts from real power plants of all kinds needed to continue to serve consumers reliably. This year, as Chairman Whitfield mentioned, EPA issued a rule exempting behind-the-meter diesel generators from Clean Air Act requirements applicable to other generators. This allows owners of these unregulated diesel generators to link up as virtual power plants to merely shift, not actually reduce their demand, and still get paid by other consumers as demand response.

This diverts consumer dollars away from cleaner generation. This has also been flagged as a reliability concern and PJM by the independent market monitor. Demand response subsidies and policies deserve greater scrutiny as, at present, they adversely impact every supply option, gas, coal, nuclear and renewables.

And on the third challenge in terms of intermittent resources, the point we would leave with you is really twofold. One is that the larger regional markets that we favor because they are larger, can handle the intermittent resources better, and the natural gas-fired power plants that are needed to back up these intermittent resources need to be properly compensated.

And with that, I thank you for the opportunity to be here, and we look forward to the questions.

[The prepared statement of Mr. Shelk follows:]

Summary of Testimony of John E. Shelk, President and Chief Executive Officer
Electric Power Supply Association (EPSA)
Grid Reliability Challenges in a Shifting Energy Resource Landscape (May 9, 2013)

EPSA is the national trade association for competitive wholesale electricity suppliers. The competitive sector accounts for 40 percent of U.S. generating capacity. These suppliers are the primary sources of electricity for most of the states from Maine to Virginia, across to Illinois, and in Texas and California. EPSA members operate a fuel diverse fleet of power plants.

The competitive business model generally places the significant risks associated with power plant development and operation on investors. As the energy resource landscape continues to shift with advances in technology impacting both supply and demand, these risks are not borne by consumers in competitive markets as they are under the traditional cost-based utility model.

The nation ignores the inherent weakness of energy forecasts at its peril. Just in the past eight years we have witnessed the headlines that "King Coal is Back" then the "Nuclear Renaissance" followed by the "Renewables Revolution." The "shale natural gas gale" will <u>not</u> be the last game changer. What's next in cleaner coal, solar, smart grid, storage, modular nuclear reactors, natural gas technologies, electric vehicles, efficiency, distributed generation and demand-side management? The variables are numerous, the possibilities nearly endless and risks are great.

On electric/gas coordination, EPSA members, as large consumers of natural gas, have a major stake in robust natural gas supplies and a reliable delivery network because under the competitive model, power plants do not earn their primary source of revenue unless their plants run, which requires gas-fired plants to have reliable access to competitively-priced natural gas.

There are many ways by which natural gas-fired power plants procure fuel. One way is firm transmission on an interstate pipeline, but it is not the only way and it is not always the most cost-effective or operationally-feasible. Firm transportation on interstate pipelines should remain a business option, not something to be mandated. The electric/gas challenge varies by region and thus a regional approach is preferable to a top-down federal solution. The regional approach is working and FERC is to be commended for its attention to these issues in a thoughtful manner.

Demand-side resources are retail matters under the Federal Power Act. Demand Response as a resource has a role to play, but that role cannot come at the expense of reliability and the health of competitive wholesale markets. No amount of Demand Response can substitute for the megawatts that will be needed to keep the grid reliable. FERC went beyond its statutory authority in Order No. 745 now pending review in federal court. EPA acted unwisely in exempting diesel back-up generators being paid as Demand Response from Clean Air Act rules. Demand Response threatens to undermine the reliability of capacity markets without reforms.

The advantage of competitive markets is that as the resource landscape shifts, consumers are not tethered to obsolete, unnecessary, more expensive means of supplying and using electricity. Regulation, however, needs to keep up. Flexible resources, such as natural gas plants, must be compensated for providing electricity when intermittent resources do not. Policymakers should avoid interfering in ways that distort market prices and undermine market revenue streams.

EPSA

Testimony of John E. Shelk
President and Chief Executive Officer
Electric Power Supply Association

Before the U.S. House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy and Power

American Energy Security and Innovation: Grid Reliability
Challenges in a Shifting Energy Resource Landscape

May 9, 2013

Chairman Whitfield, Ranking Member Rush and Members of the Subcommittee, thank you for the opportunity to participate in today's hearing on grid reliability challenges in a shifting energy resource landscape.

Introduction to EPSA and Competitive Electricity Markets

The Electric Power Supply Association (EPSA) is the national trade association for competitive wholesale electricity suppliers, including power generators and marketers. EPSA members include both independent power producers and the wholesale supply businesses of utility holding companies. EPSA members supply electricity nationwide with an emphasis on the two-thirds of the country located within a regional transmission organization or independent system operator (so-called "organized markets"). EPSA members and other competitive suppliers account for 40 percent of the installed electric generating capacity in the United States. These suppliers are the primary sources of electricity for most of Maine to Virginia, across to Illinois, and in Texas and California.

EPSA members individually and collectively operate a fuel diverse and technologically innovative fleet of power plants. EPSA members are the largest or among the largest operators of natural gas, nuclear, geothermal and solar power plants, own substantial lower-emission coal assets, and are major wind developers.

EPSA's competitive electricity companies are implementing the vision that this Committee and its Senate counterpart started with the "exempt wholesale generator" provision of the Energy Policy Act of 1992. That set in motion what became a paradigm shift in power generation business models and the regulation of wholesale markets. Competitive suppliers do not have a cost-based regulatory recovery mechanism as is the case with traditional cost-of-service utilities with monopoly service territories. Competitive suppliers must earn market revenues within detailed rules set by the Federal Energy Regulatory Commission.

Competitive Electricity Enhances Flexibility, Adaptability and Innovation

The competitive business model shifts the considerable risks of power plant development and operation from consumers to investors. This means that as the energy resource landscape continues to shift, often in dramatic ways, the considerable risks associated with how much supply and of what type should meet what amount of expected demand through various means as technologies advance (supply and demand resources) are not borne by consumers as they are under the traditional utility regulatory model.

The Committee on Energy and Commerce is wise to be focusing on the grid reliability challenges in a shifting energy resource landscape. Today policymakers and market participants understandably focus on the so-called "shale gale" stemming from prolific new supplies of natural gas. This Committee can take credit for having the foresight in the 1980's to repeal the price controls on natural gas that skewed the market toward higher priced sources of natural gas while also repealing the provisions of the Fuel Use Act of 1978 that essentially prohibited the use of natural gas in power generation. Had this Committee not taken those actions decades ago, the shale natural gas revolution would not be occurring. Yet before it blossomed in the past several years, experts were convinced that the United States would become a net importer of natural gas, not a potential exporter.

The nation ignores this lesson of the inherent weakness of energy forecasts at its peril. Just in the past eight years I have been at EPSA, we have witnessed the headlines that "King Coal is Back" then the "Nuclear Renaissance" followed by the "Renewables Revolution" and now the debate is whether natural gas-fired power generation is a bridge to the future or the future destination itself. What we do know is that the "shale gale" will <u>not</u> be the last game changer. What's next in cleaner coal, solar, smart grid, storage, modular nuclear reactors, natural gas technologies, electric vehicles, efficiency, distributed generation and demand side management? The variables are numerous and the possibilities are nearly endless.

Against this backdrop, EPSA's testimony focuses on three specific challenges: (1) electric/gas coordination; (2) declining demand and increasing Demand Response; and (3) the economic integrity of power market rules.

Electric/Gas Coordination Is Best Handled On A Regional Basis

On electric/gas coordination, EPSA viewed with interest the Subcommittee's March 19 hearing focused on this important topic. EPSA members, as large consumers of natural gas, have a major stake in robust natural gas supplies and a reliable natural gas delivery network. EPSA members with natural gas assets have as much interest as anyone in making sure natural gas supplies can be delivered to their power plants when needed to generate electricity. This is so because under the competitive business model, power plants do not earn their primary source of revenues (sales of electricity) unless the power plants run, which requires reliable access to competitively-priced natural gas.

There are many ways by which gas-fired power plants procure fuel to reliably generate electricity day in and day out. One way is to purchase firm transmission on an interstate pipeline, but it is not the only way and it is not always the most cost-effective or operationally-feasible. Furthermore, some plants are not served by interstate pipelines but instead get fuel from local natural gas distribution companies. Thus, firm transportation on interstate pipelines is and should remain a business option for power plants, not something to be mandated.

Before listing the various other ways that competitive natural gas power plants cost-effectively manage natural gas supplies, it is important to understand the nature of a power plant's demand for natural gas. The timing and volume of natural gas demand to generate electricity is highly uncertain and variable; natural gas for power generation is not consumed ratably or predictably. Demand for electricity changes by the second, hour, day, month, season, and year, as well as across decades. In addition, natural gas power plants are major but not the only sources of electricity in a given state or region; thus they compete with other fuels.

To supply consumers with the least-cost resource mix, grid operators use economic dispatch to decide which plants operate to meet demand. Power plants are generally dispatched in short time increments on a least cost basis within transmission constraints. These plants receive revenues for the sale of electricity from the day-ahead and real-time energy markets administered by RTOs/ISOs. Many of these regions serve states that elected to provide their consumers with the benefits of customer choice through retail competition based largely on annual contracts. Thus, there are timing and quantity mismatches between the nature of electricity, the design of wholesale and retail electricity markets, and the desire of at least some pipelines to push the risk of building new pipeline capacity on which they would receive a regulated rate of return on to power generators and their customers via requiring multi-decade firm natural gas transportation contracts.

To best serve consumers, power plants have many options to tailor how and when they obtain fuel in ways that reduce the cost of generating electricity reliably. Power plants can negotiate packaged services from producers and marketers that include firm or interruptible gas transportation that the producer or marketer has contracted for with an interstate pipeline. Power plants can enter into interruptible pipeline contracts directly or they can use the secondary release natural gas transportation market which is a win-win for electricity and natural gas consumers. In this manner, a holder of firm gas transportation that has capacity it will not be using (such as a local natural gas distribution company) can re-sell it to a power plant. This offsets the local gas utility's costs and uses the gas delivery system more efficiently.

Thankfully, these various commercial arrangements work exceptionally well virtually all of the time even under stressful conditions, such as particularly cold weather in New England. This observation is not to diminish at all the importance of making sure that electric/gas coordination issues are addressed to prevent the lack of natural gas deliverability from causing a shortage of electricity. Rather, it is to stress that it is important to go about addressing these electric/gas challenges in a manner consistent with competitive wholesale and retail electricity markets that federal and state policymakers have chosen to adopt, and for good reason in terms of delivering affordable electricity at lower risk to consumers.

The electric/gas coordination challenge varies by region and therefore a regional, stakeholder-driven approach with fair and transparent collaboration and communication is preferable to a "one-size-fits-all" top-down federal solution. A regional approach can take into account multiple factors that vary widely across regions including (1) the level of gas storage and shale gas development, (2) the fuel-resource mix, (3) wholesale and retail power market design, and (4) the level of development of interstate natural gas pipelines, among numerous other factors.

The regional approach is working and FERC is to be commended for its attention to these issues in a thoughtful manner. As you learned in the earlier hearing, FERC held a series of regional conferences on electric/gas issues last year with follow-up technical conferences on specific issues this year. Various electric and natural gas trade associations have been working on these issues even longer and we continue to do so. In New England, ISO New England is engaged in a formal effort with stakeholders to examine and address these issues. EPSA's regional partner, the New England Power Generators Association (NEPGA), co-chairs the regional "focus group" on this subject. FERC recently approved new scheduling times for ISO New England that will better align when in the prior day power plants are notified to operate to provide more time to arrange for natural gas. ISO New England would benefit from allowing generators to update their power bids as natural gas costs change during the day, particularly during winter months.

In addition, New England states are encouraging a conversion from home heating oil to natural gas for economic and environmental reasons. This means that local natural gas distribution companies may have a larger role to play in contracting for the build out of the regional natural gas delivery infrastructure.

Demand Response Poses Reliability Challenges That Need Attention

The second set of challenges is on the demand side, including the extent to which Demand Response is not being regulated consistent with grid reliability.

While policymakers and market participants tend to focus on and indeed tussle over which supply source of electricity is preferable, the changing landscape on the demand side deserves as much if not more Congressional attention. Recent reports from the Energy Information Administration, regional grid operators, private forecasters, and power sector financial analysts all confirm that the nation is likely facing a relatively flat demand for electricity in coming decades even as the economy recovers (with some pockets of state and regional load growth).

Expectations of lower power demand growth are a marked shift from prior forecasts that until recently projected that demand would pick up. The reasons are structural and focus on efficiency standards, energy management options, and the changing mix of the nation's economy to less electricity-intensive sectors. The consequences are profound. For competitive suppliers there will be less demand to serve from which to earn market revenues to recover the costs of long-term investments. For traditional rate-base utilities, flat demand at a time of rising costs for generation, transmission and distribution means more frequent rate cases seeking ever higher rates, which will start making competitive wholesale and retail supply options more attractive to policymakers and consumers in those states.

The other component of this second challenge is Demand Response, which involves some consumers paying others to use less electricity (so-called "nega-watts"). When this Committee and the Congress acted on this subject in Section 1252 of the Energy Policy Act of 2005 and Section 529 of the Energy Independence and Security Act of 2007, Congress was careful to only direct the Department of Energy and the Federal Energy Regulatory Commission to work with the States. This is because demand side resources are inherently retail matters that the Federal Power Act since its enactment decades ago has reserved to the States. Congress specifically limited the federal role to preparation of a National Action Plan and similar technical measures to pursue how customers could be properly incented to reduce demand below what they would otherwise consume.

Demand Response as an energy resource has a role to play in meeting our nation's electricity needs, but that role cannot come at the expense of grid reliability and the long-term health of competitive wholesale power markets. No amount of Demand Response can substitute for the substantial supplies of actual megawatts that will be needed to keep the grid reliably serving consumers.

Unfortunately, FERC went well beyond its statutory authority in Order No. 745 (2011) that overpays Demand Response in organized wholesale energy markets as if it were actual power generation without having to meet the same regulatory requirements. EPSA, American Public Power Association, Edison Electric Institute, and National Rural Electric Cooperative Association filed a joint petition for review of Order No. 745 now pending before the U.S. Court of Appeals for the District of Columbia Circuit (briefs filed, awaiting oral argument).

The Committee should also be aware that this past January, U.S. EPA issued a final rule setting National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE NESHAPS). Included in that rule are provisions exempting back-up diesel generators from Clean Air Act requirements applicable to other generators. The practical effect in the organized power markets is to allow for-profit, third-party aggregation firms to assemble back-up diesel generators as virtual power plants to masquerade as "Demand Response." This diverts consumer dollars away from cleaner sources of power generation and Demand Response that actually reduces rather than merely shifts demand. A long list of environmental organizations, public health advocates, state regulators, power generators, and trade associations including EPSA is challenging this rule in the U.S. Court of Appeals for the District of Columbia Circuit and before EPA on reconsideration.

Demand Response also threatens to undermine the reliability of the capacity markets in key regions unless reforms are implemented. In PJM, the Reliability Pricing Model (RPM) procures capacity three years ahead to assure future reliability. The volume of Demand Response, paid for by consumers via RPM, has skyrocketed in recent years to over one-half the reserve margin, including Demand Response that is limited to only 60 hours per year or seasonally. This has prompted serious recent warnings from Monitoring Analytics, PJM's independent market monitor, about the potential adverse impact on reliability (*Analysis of Replacement Capacity for RPM Commitments* issued December 12, 2012 and the *State of the Markets Report* issued March 14, 2013). This tracks similar concerns in the North American Electric Reliability Corporation's *2012 Long-Term Reliability Assessment* (November 2012). California and Texas are looking to rely more on Demand Response and should heed the lessons painfully learned in PJM and elsewhere about how to regulate it to be a reliable and comparable resource.

Generators must meet numerous preconditions to bid in capacity auctions with specific long-term assets. Unfortunately, on procedural grounds FERC recently rejected PJM's attempt to strengthen the requirements for Demand Resource to assure reliability in time for this month's auction to procure capacity for the 2016/17 delivery year. To its credit, FERC did act recently to improve testing to address some but not all concerns with Limited Demand Response.

Proper Market Design, Rules and Practices Are Critical to Reliability

The third challenge to grid reliability takes this discussion back to where the testimony started. It is often said that the U.S. has a "hybrid" electricity system, as if there are only two business models for generating electricity (competitive and monopoly) and two corresponding regulatory regimes. In fact, states and regions fall in many places along a continuum between cost-based regulation and markets.

The shifting resource landscape, both as to supply and demand components, affects all regions, states and types of electricity providers. The advantage of competitive wholesale and retail markets is that, as the energy resource landscape shifts, often disrupting assumptions, consumers are not tethered to what become obsolete, unnecessary, more expensive means of supplying and using electricity.

Regulation, however, needs to keep up. For example, the growth of intermittent resources such as wind and solar argues for large regional markets that can more reliably manage resources across a wider footprint. It means that flexible resources, such as natural gas plants, must be fully compensated for standing by and providing electricity when intermittent resources do not. It also means that while percentages may change among resource types, the work horses of coal and nuclear will continue to play important roles in maintaining a reliable grid.
Finally, for competition to work, policymakers should avoid interfering in power markets in ways that distort market prices and undermine market revenue streams.

Conclusion

The Electric Power Supply Association greatly appreciates this opportunity to participate in today's hearing and in the Committee's future deliberations on these and other electricity issues.

The three challenges addressed in today's testimony are among many that policymakers, market participants, consumers, and other stakeholders must successfully meet. Electricity is correctly described as the life-blood of the modern economy and essential to deploying the technological advances that innovation has made possible. These advances make our lives, economies and environment better. It is clear that achieving the full potential in this regard requires affordable, reliable, environmentally-responsible supplies of electricity and the efficient use of these important sources of energy.

EPSA members are proud of the substantial role they play as major providers of electricity across the country on a competitive basis, as thoughtful leaders in public policy debates, and as innovators investing private capital at market risk to improve the nation's electricity supply system to maintain grid reliability while achieving broader public policy objectives. I look forward to the testimony of the other witnesses on today's panel and to the Subcommittee's questions on these important topics.

Mr. WHITFIELD. Thanks very much.

And Mr. Cicio, you are recognized for 5 minutes.

STATEMENT OF PAUL CICIO

Mr. CICIO. Thank you. Mr. Chairman, Ranking Member Rush, members of the subcommittee, thank you for the opportunity to be here. My name is Paul Cicio, and I am the president of the Industrial Energy Consumers of America. IECA is a trade association. Our manufacturing companies have revenues of $1.3 trillion, over 1,500 major manufacturing facilities across the United States, and we employ some 1.7 million people.

IECA companies are mostly energy intensive trade exposed industries. This means that they are substantial consumers of natural gas and electricity and that relatively small changes in the price of energy can have a significant impact on competitiveness and jobs. The industrial sector uses about one-third of the U.S. natural gas and one-third of the U.S. electricity.

The key message of this testimony to Congress is that consumers are not being served by a combination of actions and inactions by policymakers, all of which potentially threaten electric and natural gas reliability.

Because the electric reliability is dependent upon natural gas pipeline capacity reliability and that no federal agency apparently has responsibility for oversight of natural gas pipeline reliability means, in general, that no one in Washington is in charge of reliability. The U.S. cannot have electric reliability without having natural gas pipeline reliability.

Everyone is aware of the northeast corridor pipeline constraints and how it increased prices. Thankfully, policymakers are working to resolve the problem.

What IECA is worried about is what we do not know about the pipeline constraints in other parts of the country. The question that keeps us up at night is, given the momentous market changes under way over the next 4 years, at peak natural gas demand periods like very hot summer days or very cold winter nights, will there be adequate natural gas pipeline capacity for all natural gas consumers?

While the North American Electric Reliability Corporation, NERC, has responsibility for overseeing electric reliability and appears to be doing a good job, there is no such organization for overseeing natural gas pipeline capacity reliability. FERC has authority over most aspects of natural gas pipelines but not reliability. Their view—they view reliability as responsibility of the market. The decision to build a pipeline is a market decision, not a regulatory decision, and we agree with that premise.

While the premise of a pipeline decision to build or not build has not changed and shouldn't change, the market it serves has changed profoundly in several complicated ways that greatly increased the potential for reliability problems that never existed before, all at the same time and over a compressed period of time. And we must be mindful that potential solutions in this arena are capital intensive and where timely environmental permitting is a huge obstacle to speed. These facts make a compelling case for what oversight and studies evaluating reliability at future peak demands are necessary to prevent future reliability problems.

In contrast, for electric reliability, NERC is doing studies to encompass the country to evaluate and provide vital information that supports pre-emptive action by policymakers and markets to guard against electric reliability problems.

The recent study completed by the Midwest Independent System Operator, MISO, clearly demonstrates the need for greater oversight and study. The MISO study concluded, in the short term, more than 65 percent of the pipelines currently supplying gas to 13 Midwest states has insufficient capacity to fully meet its needs from existing generating units. For the period 2016 to 2030, almost 90 percent of the pipelines have insufficient capacity. The results of this study should have served as a red flag to policymakers, but it apparently has not had quite the effect that we would like.

Lastly, how FERC and the regional markets respond to these challenges may result in consideration of policy changes that could be of concern to the industrial sector. For example, a FERC policy that gives certain rights and priorities to electric generators for access to natural gas pipeline capacity may provide potential solutions to electric generation reliability but creates reliability and cost problems for manufacturers.

Mr. Chairman, in conclusion, reliability is an important safety and cost issue. Policymakers should not wait until there are rolling brownouts or blackouts to provide oversight of natural gas pipeline capacity.

[The prepared statement of Mr. Cicio follows:]

"Grid Reliability Challenges in a Shifting Energy Resource Landscape"

Before the House Committee on Energy and Commerce, Subcommittee on Energy and Power

Thursday, May 9, 2013

Testimony of
Paul N. Cicio
President
Industrial Energy Consumers of America

Chairman Whitfield, Ranking Member Rush, and Members of the Subcommittee, thank you for the opportunity to testify before you on this important issue. My name is Paul Cicio, and I am the president of the Industrial Energy Consumers of America (IECA).

IECA is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 1,500 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemical, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, brewing, and cement.

IECA companies are mostly energy-intensive trade-exposed industries. This means that they are substantial consumers of natural gas and electricity, and that relatively small changes to the price of energy can have significant direct impact on competitiveness and jobs. According to the Energy Information Administration (EIA), the industrial sector uses about one-third of U.S. electricity and natural gas.

The key message of this testimony to Congress is that consumers are not being served by a combination of actions and inactions by policy makers – all of which potentially threaten electricity and natural gas reliability. Because the electric reliability is dependent upon natural gas pipeline capacity reliability, and that no federal agency apparently has responsibility for oversight of natural gas pipeline reliability – means that no one in Washington is in charge of reliability! The U.S. cannot have electric reliability without natural gas pipeline reliability.

Key points:

1. Manufacturing companies are concerned about reliability and its potential cost impact.
2. No one is in charge of natural gas pipeline reliability.
3. How FERC addresses these challenges is important to industrial competiveness.
4. Greater use of CHP/WHR power generation and use of other forms of energy efficiency and demand response should be considered by FERC.
5. LNG exports peak demand is expected during U.S. winter demand season, increasing reliability concerns, and natural gas and electricity prices.

1. Manufacturing companies are concerned about reliability and its potential cost impact.
Manufacturing companies are concerned about electric reliability due to potential natural gas pipeline capacity constraints and increased dependence on natural gas-fired power generation.

The natural gas and electricity industries provide a service that goes beyond the issues of health and safety. These are services that can determine the competitiveness of the industrial sector with direct and indirect impact to jobs. How efficiently the natural gas and electricity industries operate and at what cost have broad impacts to economic growth and capital investment.
In this regard, IECA has two concerns: The potential for natural gas and electric reliability problems that become a safety and cost issue for a manufacturing facility; and the policy changes that the FERC may consider to respond to the challenges in a timely manner.

2. No one is in charge of natural gas pipeline reliability.
Everyone is aware of the NE corridor pipeline constraints and how it has increased prices. Thankfully, policy makers are working to resolve the problem.

What worries IECA is what we do not know about pipeline constraints in other parts of the country. The announced shut down of about 50 GW of coal and oil-fueled power generation units due to EPA regulations, and approximately $100 billion in new natural gas driven industrial facilities, will place a lot of new demand on the existing pipeline infrastructure.

The question that keeps us up at night is... "Given the momentous market changes underway over the next four years, at peak natural gas demand periods like a very hot summer day or a very cold winter's night, will there be adequate natural gas pipeline capacity for all natural gas consumers?"

While the North American Electric Reliability Corporation (NERC) has responsibility for overseeing electric reliability and appears to be doing a good job, there is no such organization for overseeing natural gas pipeline capacity reliability. FERC has authority over most aspects of natural gas pipelines but not reliability. They view reliability as a responsibility of the "market." The decision to build a pipeline is a market decision, not a regulatory decision. We agree with this premise.

While the premise of a pipeline decision to build or not has not changed (and should not change), the market it serves "has changed profoundly" in several complicated ways that greatly increase the potential for reliability problems that never existed before, all at the same time and over a compressed period of time. And, we must be mindful that potential solutions in this arena are capital intensive and where timely environmental permitting is a huge obstacle to speed. These facts make a compelling case for why studies evaluating reliability at future peak demands are necessary to prevent future reliability problems.

Examples how the market has changed to potentially threaten reliability include:

- It is increasingly difficult to build pipelines where they are needed most.
- The confluence of significant shutdown of coal-fired power generation in a short 3-4 year period creates significant new demand and reliability threats. Greater reliance on natural gas power generation increases the severity of daily peaking demand. At peak, is there sufficient capacity to supply competing demand with residential and industrial demand?
- The necessity of many remaining coal-fired power plants to shut down for retrofitting new environmental controls over the next 3-4 years creates significant demand on gas-fired units.
- The significant new natural gas demand by the growing manufacturing renaissance places demand on the same pipelines that are needed to supply gas for power generation.
- LNG export demand will create seasonal winter demand essentially using U.S. storage as their storage. LNG exports of 4.0 to 7.0 Tcf of demand will also consume significant pipeline capacity.
- There are significant changes to pipeline flows. Plus significant changes to existing pipelines, some converting from natural gas to oil and vice versa.

The cumulative impacts of these new market changes demand more oversight to ensure the reliability of natural gas and electricity.

In contrast, for electric reliability, NERC is doing studies that encompass the country to evaluate and provide vital information that supports preemptive action by policy makers and markets to guard against electric reliability problems. And while some regional market organizations like the Midwest Independent System Operator (MISO) are doing studies that look at natural gas pipeline capacity, it only looks at the pipeline capacity in that 13 state region and does not evaluate new loads on those same pipelines before they enter MISO or after they leave. A national overview is needed.

Nonetheless, the MISO study reaffirms potential serious natural gas pipeline reliability concerns. In the analysis, MISO evaluates the impacts of the anticipated closure of substantial generation resources within its footprint and models the requirements to replace that generation.

MISO utilities currently plan to retire 12.6 GW of coal-fired generation in the near term, amounting to about 9 percent of total current capacity. The study concluded that in the short term, more than 65 percent of the pipelines currently supplying gas into the Midwest has insufficient capacity to fully meet the needs of the existing generating units operating at expected capacity factors. For the period 2016-2030, almost 90 percent of the pipelines have insufficient capacity for the existing generating units plus the incremental 12.6 GW coal-to-gas retirement scenario. The results of this study should have served as a red flag to policy makers – but it has apparently not had this effect.

3. How FERC addresses these challenges is important to industrial competiveness.
How the FERC and the regional markets respond to these challenges may result in consideration of policy changes. In that light, IECA offers several examples of potential policy changes that could negatively impact the industrial sector.

FERC policy that gives certain rights and priority to electric generators for access to natural gas pipeline capacity may provide a potential solution to the electric generation reliability problem but creates a reliability and cost problem for manufacturers regarding their access to such capacity. IECA is concerned about the subordination of all other uses to the needs of a single type of customer – the electric generator. Such an approach would be discriminatory and result in costs that would damage the competitiveness of manufacturing.

a. Maintain no bumping rules
Maintain "no-bumping" rules that provide certainty to a manufacturer that has scheduled their gas for a given day, will not be interrupted to accommodate variable loads, and is critical to manufacturers.

b. Maintain rules that do not discriminate
We are concerned about setting rules or tariff revisions that would give priority to natural gas pipeline loads that serve power generators that have high potential intraday variability. This could force more restrictive multi-intraday or even hourly balancing requirements with stricter imbalance tolerances on "all" pipeline users which would be especially problematic for industrial manufacturing facilities. This rebalancing could result in increased costs and possibly reduced operational flexibility for industrial consumers. In other words, our reliability can become

compromised due to power generator requirements which are fundamentally different from industrial requirements demands.

c. FERC should utilize cost causation principles

If there are increased natural gas interstate pipeline costs to support greater natural gas and electric coordination, it is essential that the current precedent for use of straight fixed variable methodology continue to be used by the FERC for allocating those incremental costs. In addition when implementing this policy, it is FERC precedent when integrating pipeline infrastructure costs that overall rates to customers not exceed 10% of the then current rates, and to require the parties requesting the increased capacity to pay "aid in construction" to the interstate pipeline for the incremental costs not allocated to users via the 10% rule. The industrial consumers who rely on that pipeline capacity should not be expected to pay for the additional costs. Fundamentally, our view is that cost causation principles should prevail and that entities who "cause" the cost should pay for the cost above a threshold level.

d. Potential limits to firm natural gas pipeline capacity

As utilities add more natural gas-fired generation to replace coal and to serve as backup to the intermittent renewable generation, they are contracting for firm natural gas transportation capacity from the interstate pipelines. In many cases they are only using this pipeline capacity on an intermittent basis when the gas-fired electric generation units are operated. However, they contract and pay for the firm capacity to ensure that they can get gas to their units when needed. They can afford to do this because they pass on the cost of the firm transportation capacity to their electricity customers. Oftentimes the utilities will not release the capacity when it is not being used so that others could use it as secondary firm. These operational practices limit the amount of primary or secondary firm pipeline capacity available to industrial manufacturing companies. Coordination and communication is needed between the electricity and natural gas markets to ensure that the pipeline capacity is utilized properly and that firm capacity will continue to be available for manufacturing.

e. Changing natural gas pipeline flows are an issue

The expanded use of natural gas for electricity generation has and will continue to change flow patterns on the natural gas pipeline system. Areas that historically were supplied by Gulf Coast pipelines are now being supplied by new natural gas production from the Marcellus Shale reservoir basins resulting in low rates of capacity utilization and problematic higher rates for industrial companies who may have contracted for firm capacity on those Gulf Coast pipelines.

4. Greater use of CHP/WHR power generation and use of other forms of energy efficiency and demand response should be considered by FERC.

a. Include industrial CHP and WHR as a supporting policy solution

FERC should evaluate the role of industrial cogeneration of power and steam and use of waste-heat-to-power as a supportive policy solution to increasing reliability of the grid through increased distributive power generation. There is a substantial existing capacity of under utilized CHP capacity that with the right policy could provide a source of distributive power supply. Likewise, there is a significant quanity of manufacturers across the country that have excess steam or waste heat that could be converted to economical distributed power generation through the construction of new units. There is substantial side benefits to considering this policy option. Greater use of CHP and WHR increases the competitiveness of the manufacturing sector thereby increasing high paying jobs, exports and economic growth. A win-win.

b. FERC should include use of energy efficiency as a policy tool

IECA encourages the FERC to broaden its analysis beyond hard electric generation supply sources and also consider all forms of energy efficiency, including demand side management and end-use efficiency, which can serve as low-cost methods to both effectively replace base load generation as well as enhance grid reliability. In this respect, we applaud FERC Order 745 that supports use of demand response. We also support FERC's effort to better quantify the benefits of demand response and efficiency in wholesale markets as set forth in Docket No. RM05-5-020.

We encourage the FERC to streamline the process for industry financed and installed energy efficiency to participate in the PJM capacity auctions and in the capacity constructs implemented by other RTOs and ISOs. The measurement and verification (M&V) protocols that have been developed for energy efficiency participation in this market are too cumbersome and expensive for the industrial sector to undertake. The extensive requirements for M&V appear to be designed for utility participation through use of consultants. Industrial users are unlikely to retain consultants to provide the measurement and verification plans that are required for energy efficiency to participate in capacity markets. There would be much greater participation in these auctions by the industrial sector if the M&V requirements were streamlined for industrial participants.

Importantly, if energy efficiency is pursued as an option, it is vital that industrial companies retain the flexibility to opt out at the state level if companies determine the benefits are not cost effective to the companies.

5. LNG exports peak demand is expected during U.S. winter heating demand season, increasing reliability concerns, and natural gas and electricity prices.

All of the major LNG importing countries are located in the northern hemisphere which means their winter peak demands for LNG will occur when the U.S. is in its peak demand (see Chart 1 below). Higher seasonal demand from LNG could impact reliability and place upward pricing pressure on both natural gas and electricity for all U.S. consumers.

Countries that import LNG have very little storage. This means that essentially, these foreign countries will be using U.S. storage as their storage. Supplying natural gas for export facilities will also consume pipeline capacity in regional markets.

Experts' forecasts of LNG demand vary greatly but range from 4 to 7 Tcf of new natural gas demand. Considering U.S. 2012 demand was 25.5 Tcf, we could experience an unprecedented increase in demand of between 16 percent and 27 percent.

Chart 1

LNG Imports by Country, 2010

Importer	MMtpa
Japan	70.6
South Korea	34.1
Spain	20.5
UK	14.2
Taiwan	11.6
France	10.5
China	9.5
India	9.3
US	8.5
Italy	6.7
Turkey	5.9
Belgium	4.5
Mexico	4.4
Chile	2.3
Portugal	2.2
Kuwait	2.1
Brazil	2.0
Canada	1.5
Argentina	1.3
Greece	0.9
Dominican Republic	0.6
Puerto Rico	0.6
UAE	0.1
Total Imports	**223.8**

Source: Waterborne LNG Reports, US DOE, PFC Energy

Reliability is an important safety and cost issue. Policy makers should not wait until there is rolling brown outs or black outs to provide oversight of natural gas pipeline capacity reliability.

Thank you.

Mr. WHITFIELD. Thanks very much.

Mr. Weiss, you are recognized for 5 minutes.

STATEMENT OF DANIEL WEISS

Mr. WEISS. Chairman Whitfield, Ranking Member Rush and members of the subcommittee, thank you for the opportunity to testify on American energy security and innovation. Discussing electricity security while ignoring climate change is like discussing personal health while ignoring smoking, diet and exercise. We must acknowledge that our electricity generation system produces much of the carbon pollution responsible for climate change and that the effects of climate change impair electricity reliability. These threats include extreme weather events, storms, floods, droughts, heat waves and wild fires.

The Congressional Research Service concluded in 2012 that, quote, "power delivery systems are most vulnerable to storms and extreme weather events," unquote. Such events also threaten American lives, the economy and taxpayers. The 25 most severe extreme weather events in 2011 and 2012 caused 1,100 fatalities and $188 billion in damages.

A Center for American Progress analysis found that federal natural disaster relief recovery efforts cost taxpayers $136 billion in fiscal years 2011 through 2013, or 400 hours per household annually, and the National Climate Assessment Draft warns us that we can expect more extreme and severe weather in the future.

Extreme weather interferes with electricity generation. The severe 2012 drought interrupted power production in many states by shrinking the amount of cooling water available for power plants. The drought also disrupted oil and natural gas production. Superstorm Sandy and other severe storms also disrupted electricity service by downing power lines and damaging facilities. We urge the subcommittee to support policies to achieve a more secure, reliable electricity system by accomplishing the following three goals.

First, Congress must slow climate change by reducing carbon pollution from power plants, the largest uncontrolled source of emissions. Failing that, EPA must comply with the Supreme Court by setting such standards under the Clean Air Act. American Electric Power, Xcel and Entergy all testified before this subcommittee earlier this year in favor of legislation to address climate change.

Second, continue to provide financial incentives for energy efficiency and renewable electricity technologies, which would reduce reliance on the polluting fossil fuels responsible for climate change, pay for them by adding tax breaks for big oil companies because they have received the most federal support over time. The Nuclear Energy Institute in a 2011 study found that over the past 60 years, 70 percent of federal energy spending went to fossil fuels while only 10 percent went for renewables. In addition, in 2013, the North America Reliability Corporation found that, quote, "no significant reliability challenges that intermittent electricity exists."

And third, reduce the vulnerability of the electricity infrastructure to extreme storms, drought, sea level rise and other impacts of climate change. Investments in resiliency to extreme weather save money. The Federal Emergency Management Agency estimates that, quote, "a dollar spent on pre-disaster mitigation saves society an average of $4 in lower damages."

Yet even as extreme weather increases, the federal government is investing less in community resilience. Representative Lois Capps and 39 colleagues have urged that the federal government undertake a resilience plan that, first, determines the financial support necessary to help communities prepare for future extreme weather events and creates a dependable revenue stream to provide additional resources for these community resilience programs.

In addition, the Congressional Research Service recommends more investment in smart grid and transmission repairs to improve electricity reliability. The growing harm from climate change requires a prompt transition from dirty to cleaner electricity generation, which is begun both here and abroad. For instance, Iowa generates 20 percent of its electricity from wind. Six years after a devastating tornado, Greensburg, Kansas is, quote, "100 percent renewable energy 100 percent of the time," unquote. Germany generated one quarter of its electricity from renewable sources over six months in 2012, so it can be done.

Congress must adopt policies that speed this transition while helping our electricity system become more resilient to damages from climate related storms, floods, drought and other extreme weather. Thank you very much.

[The prepared statement of Mr. Weiss follows:]

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Testimony on "American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape"

Subcommittee on Energy and Power of the Committee on Energy and Commerce

2123 Rayburn House Office Building
May 9, 2013

Thank you for the opportunity to testify before the House Energy and Commerce Subcommittee on Energy and Power on "American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape." U.S. electricity generation is undergoing a transition, including a measurable shift from coal to natural gas and renewable electricity sources.

Any evaluation of this transition and its impacts, however, must consider that our electricity generation produces the carbon pollution responsible for climate change, and that climate change impairs electricity reliability. A discussion about electricity security and innovation that ignores global warming is like a discussion about personal wellness that ignores cigarette smoking, diet and exercise. Since coal fired power plants emit one-third of the climate pollution in the U.S., it is irresponsible to assess changes in our electricity system while ignoring climate pollution and its impacts.[1]

This testimony will address the following issues that are essential to an informed discussion of electricity security and reliability.

1. Americans understand that extreme weather is related to man-made climate change that costs our economy billions of dollars annually
2. Electricity reliability threatened by climate related extreme weather
3. We must reduce carbon pollution from power plants
4. We must increase investments in emerging no and low carbon technologies
5. We must enhance our electricity system's resilience to damages from extreme weather

1. Climate change is real, here, and due to human activity

There is a scientific consensus that climate change is due to the emission of carbon pollution and other heat trapping gases. The production, transportation, and combustion of fossil fuels produce carbon pollution responsible for climate change. The costly damages from climate change impacts – particularly extreme weather – increase the imperative to reduce this pollution by transitioning to significantly cleaner fuels.

The National Academy of Sciences left no doubt about the scientific consensus about carbon pollution, climate change, and its impacts. It reported in 2010 that:

> There is a strong, credible body of evidence, based on multiple lines of research, documenting that climate is changing and that these changes are in large part caused by human activities...The core phenomenon, scientific questions, and hypotheses have been examined thoroughly and have stood firm in the face of serious scientific debate and careful evaluation of alternative explanations.[2]

The American Meteorological Society came to a similar conclusion last year.

> There is unequivocal evidence that Earth's lower atmosphere, ocean, and land surface are warming; sea level is rising; and snow cover, mountain glaciers, and Arctic sea ice are shrinking. The dominant cause of the warming since the 1950s is human activities. This scientific finding is based on a large and persuasive body of research.

> The observed warming will be irreversible for many years into the future, and even larger temperature increases will occur as greenhouse gases continue to accumulate in the atmosphere. Avoiding this future warming will require a large and rapid reduction in global greenhouse gas emissions.[3]

The National Climate Assessment is a congressionally mandated assessment of the latest climate science. The 2013 draft was undertaken by over two hundred scientists.[4] It determined that

> Sea level rise, combined with coastal storms, has increased the risk of erosion, storm-surge damage, and flooding for coastal communities, especially along the Gulf of Mexico, the Atlantic seaboard, and Alaska.[5]

Kevin E. Trenberth, senior scientist at the National Center for Atmospheric Research, recently noted:

> All weather events are affected by climate change because the environment in which they occur is warmer and moister than it used to be. The air is on average warmer and moister than it was prior to about 1970 … [This] contributes to more intense precipitation events that are widely observed to be occurring.[6]

These are dozens of scientific organizations that conducted or assessed independent, peer reviewed studies that all came to the same conclusion: climate change is real and humans are responsible. Those that deny this climate science are akin to tobacco industry apologists who once denied the link between cigarette smoking and cancer.

Most severe extreme weather cost 1,107 lives, $188 billion in damages in 2011-2012

The impacts of climate change – including extreme weather, sea level rise, and the spread of tropical diseases – have real costs. The U.S. was battered by many severely damaging climate-related extreme weather events over the past two years. The National Oceanic and Atmospheric Administration reported that in 2011 and 2012 there were a total of 25 floods, drought, storms, and wildfires that each caused at least $1 billion in damages.[7] Together, these 25 $1 billion-dollar minimum in damages events caused 1,107 fatalities, and caused up to $188 billion in total damages.[8] *The New York Times* warned that "the economy won't function very well in a world full of droughts, hurricanes, and heat waves."[9]

A recent study by Munich Re, the world's largest reinsurance firm, found that North America is experiencing a tremendous rise in extreme weather disasters—a nearly fivefold increase over the past three decades.[10] The firm concluded that this is due to climate change.

No state is immune to the most destructive extreme weather. For instance, between 1980 and 2012 Kentucky was harmed by three dozen severe weather events that each caused a total of at least $1 billion in damages in the affected states.[11] These events include heavy precipitation and severe thunderstorms, tornadoes, flooding, heat waves and drought. The National Climate Assessment draft noted that "The Southeast has experienced more billion-dollar in damages disasters than any other region" in the United States.[12]

Kentucky agriculture was harmed by the 2012 drought – the worst in sixty years. According to the University of Kentucky's agriculture extension program,

> "The drought dominated the U.S./Kentucky farm economy conversation in 2012. Crop yields suffered greatly and high feed costs coupled with depleted pastures and water supplies adversely impacted livestock prices and profit margins."[13]

Climate related extreme weather has continued in 2013. As of May 7th, President Barack Obama has issued 17 presidential disaster declarations for severe storms and flooding.[14] And this does not include the recent Mississippi River flooding from Wisconsin to Missouri, and the flooding in North Dakota.[15] Nor does it include the deadly California wildfires. None of these events have yet received presidential disaster declarations.

The threat of wildfires outside of California remains high too. The National Interagency Fire Center's May 1st report noted that

> "Severe drought conditions across the western U.S. had a significant effect on fuel conditions. Nearly all areas west of the Rocky Mountains… are experiencing both live and dead fuel moistures which are extremely low and raise the probability for sever early season fire activity that will likely continue into the summer."[16]

This may be due to the ongoing drought. The U.S. drought monitor shows that nearly half of the US in drought as of April 30th. It reports that "The Upper Midwest continued to deal with long-term precipitation deficits despite seasonal spring flooding, while an early end to the western Water Year caused drought to intensify across the Southwest."[17]

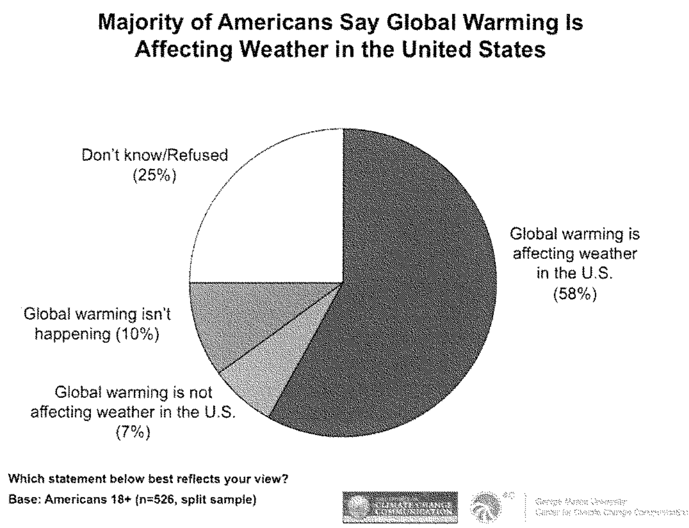
Americans understand that climate change is affecting U.S. weather

The vast majority of Americans understand that there is a scientific consensus about climate change. A recently released Gallup poll found that 62 percent of Americans believe that "scientists think warming is occurring," while 28 percent believe it is ambiguous. Only 6 percent think that scientists do *not* believe climate change is underway.[18] This poll also found that 57 percent of respondents believe that climate change is due to "human activities," while only 39 percent think it is from "natural causes."[19]

Americans also understand that the recent spate of extreme weather is related to climate change according to a recent poll by the Yale Project on Climate Communication and the George Mason University Center for Climate Change Communication.[20] Highlights from the poll include the following findings.

> About six in ten Americans (58%) say "global warming is affecting weather in the United States."
>
> Many Americans believe global warming made recent extreme weather and climatic events "more severe," specifically: 2012.

Many Americans (51%) also say weather in their local area has been worse over the past several years.



U.S. reduced climate pollution, but will miss 2020 reduction goal

In 2009 President Obama committed the United States to 2020 greenhouse gas pollution levels "in the range of" a 17 percent reduction below 2005 levels.[21] The Environmental Protection Agency recently reported that "Greenhouse gas emissions in 2011 were 6.9 percent below 2005 levels," or slightly more than 40 percent towards this 2020 goal.[22] This is due to reductions of carbon pollution from motor vehicle emissions, lower electricity demand, and a shift from coal to natural gas and renewable-electricity generation. The Energy Information Administration, however, projects that carbon pollution from the energy sector will rise again beginning in 2017 without additional action as fossil fuel generated electricity grows.[23]

Other nations are more aggressively reducing their climate pollution. The European Union's 2020 goal to lower its emissions by 20 percent compared with 1990 levels, and it is on pace to achieve it.[24] Australia and New Zealand both have programs to achieve steep reductions in carbon pollution over the next four decades.[25] [26]

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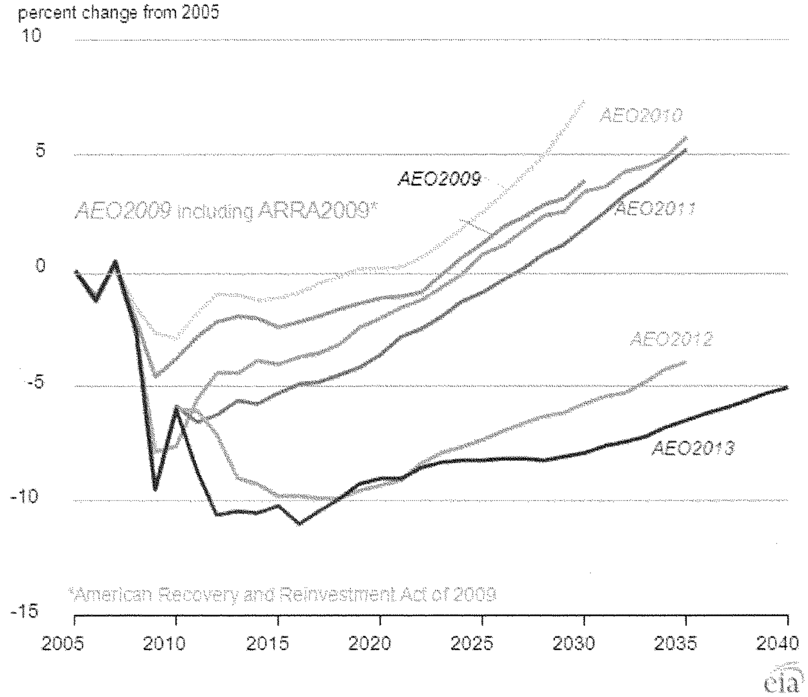
Figure 13. U.S. energy-related carbon dioxide emissions in recent AEO Reference cases

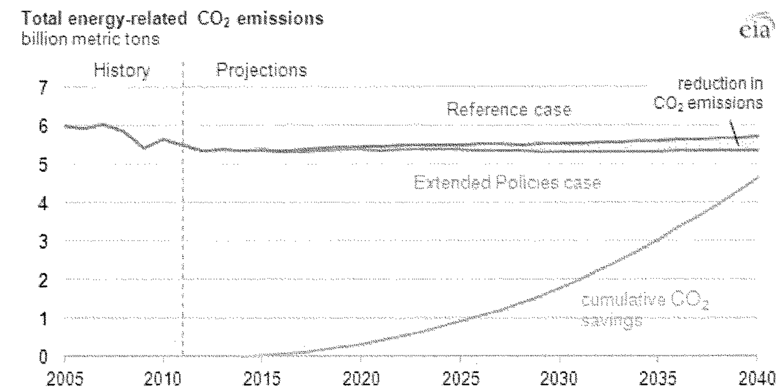


Source: Energy Information Administration

Last week EIA projected that

> Extending certain federal energy efficiency and renewable energy laws and regulations could reduce annual energy-related carbon dioxide emissions in the United States in 2040 by roughly 6% relative to a Reference case projection that generally assumes current laws and policies.[27]

However, that would still leave U.S. emissions far above the level necessary to offset the worst impacts of climate change.



Source: Energy Information Administration

<u>Federal natural disaster relief and recovery cost taxpayers $136 billion in FY 2011-13, or $400 per household annually</u>

The Center for American Progress recently released "Disastrous Spending: Federal Disaster-Relief Expenditures Rise amid More Extreme Weather," which estimates that the federal government spent $136 billion for disaster relief and recovery in 2011 to 2013.[28] These funds are from taxpayers, and are nearly $400 per home per year.

TABLE 1

Federal spending on disaster relief and recovery, 2011–2013

Fiscal year appropriations or supplemental bill spending	Estimated disaster-relief spending (in millions of $)
FY 2011	$21,376
FY 2012	$32,412
FY 2012 supplemental appropriations	$8,174
FY 2013	$14,321
FY 2013 Superstorm Sandy supplemental appropriations	$60,210
Total	$136,493

Notes: The Treasury Department has two disaster-related programs, but funding levels are unavailable. Figures are rounded.
Sources: Annual department budget reports; appropriations and supplemental appropriations law. For more detail, see the attached spreadsheet.

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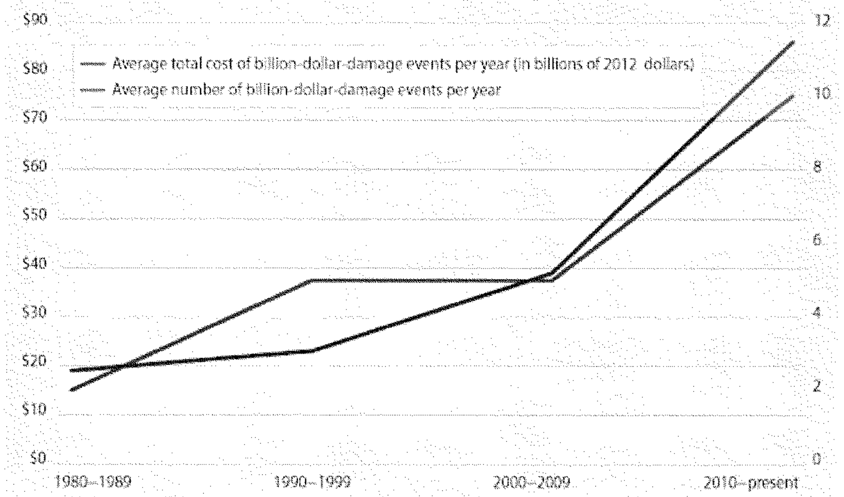
This CAP report also found that the most destructive severe weather events have grown both number and damages over the past three decades.[29] If this trend continues at the same rate, the United States will experience more frequent and severe extreme weather events in the years to come, meaning that the federal government will have to spend more and more funds on disaster-relief efforts, leaving taxpayers with the bill.

FIGURE 1

Billions of dollars in damages from extreme weather events increasing in frequency, cost from 1980–2012



Source: National Oceanic and Atmospheric Administration.

U.S. can expect more extreme and severe weather according to scientists

As if the recent bout of extreme weather is not bad enough, scientists predict that it could get much worse due to climate change. NASA just released a study that "projects warming-driven trends in rainfall…which may increase the risk for extreme rainfall and drought."[30] NASA's study predicts that

> Some regions outside the tropics may have no rainfall at all. In the Northern Hemisphere, areas most likely to be affected include the deserts and arid regions of the southwest United States, Mexico, North Africa, the Middle East, Pakistan, and northwestern China.[31]

The National Climate Assessment draft predicts that our temperature will continue to rise, and we will continue to experience extreme weather related to climate change.

> Global climate is projected to continue to change over this century and beyond. The magnitude of climate change beyond the next few decades depends primarily on the amount of heat-trapping gases emitted globally, and how sensitive the climate is to those emissions.
>
> U.S. average temperature has increased by about 1.5°F since record keeping began in 1895; more than 80% of this increase has occurred since 1980. The most recent decade was the nation's warmest on record. U.S. temperatures are expected to continue to rise.
>
> Heavy downpours are increasing in most regions of the U.S., especially over the last three to five decades. Largest increases are in the Midwest and Northeast. Further increases in the frequency and intensity of extreme precipitation events are projected for most U.S. areas.
>
> Global sea level has risen by about 8 inches since reliable record keeping began in 1880.It is projected to rise another 1 to 4 feet by 2100.[32]

More extreme weather is also predicted for the southeast United States by the National Climate Assessment draft.

> The Southeastern region is exceptionally vulnerable to…extreme heat events, and decreased water availability.
>
> Temperatures across the Southeast are expected to increase during this century, fluctuating over time because of natural climate variability. Major consequences of warming include significant increases in the number of hot days (95F).
>
> Summer heat stress is projected to reduce crop productivity, especially when coupled with increased drought.[33]

2. Electricity reliability threatened by climate change

Like many other categories of infrastructure, electricity generation and transmission are vulnerable to extreme weather, and by extension, climate change. The Congressional Research Service evaluated the impact of weather on electricity reliability in its "Weather-Related Power Outages and Electric System Resiliency" report from August 2012.[34] It concluded that "power delivery systems are most vulnerable to storms and extreme weather events."[35]

CRS determined that "Cost estimates from storm-related outages to the U.S. economy at between \$20 billion and \$55 billion annually. Data also suggest the trend of outages from weather-related events is increasing."[36]

The Department of Energy's database of grid disturbance events also shows an increasing number of power outages from 1992 to 2010, and that 78 percent of the reported 1,333 grid disruptions were weather-related.[37] Evan Mills, the author of the DOE study, "believes the reasons for the increased trend in outages may be due to a combination of power grid deterioration and a real increase in the number of observed extreme weather events."[38]

Severe drought of 2012 interfered with electricity generation

In addition to severe storms disrupting power transmission, extreme drought reduces water flows that can impair the operation of electricity generation units because they require huge amounts of water for "cooling, fuel processing, and emission control," according to the Department of Energy.[39]

The severe drought of 2012 interfered with the operation of numerous power plants. In August 2012, National Geographic magazine reported

> Record heat and drought conditions across the United States this summer have plagued power plants that require cool water to produce electricity. From Connecticut to California, high water temperatures and diminished access to water caused by drought have forced a number of power plants to ramp down production... At least one plant has suspended operations.[40]

For instance, the Millstone nuclear plant in Waterford, CT had to shut down in mid-August 2012 because water from the Long Island Sound "was too warm to cool critical equipment outside the core. Two Midwestern coal plants – one in Illinois- had to stop operating because of low water levels and "water-intake pipelines ended up on dry ground from the prolonged drought." [41]

The Department of Energy concluded that "Drought (affected by climate change) combined with possible exhaustion of aquifers could lead to population and power use shifts that could change electrical load patterns."[42]

Fracking for tight oil and shale gas vulnerable to extreme weather, too

A significant portion of the transition from coal to natural gas, and from imported to domestic oil, is driven by the recent expansion of the production tight oil and shale gas via hydraulic fracking. This technique requires copious amounts of water. A shale gas well requires at least one million gallons of it.[43] Climate related extreme weather – particularly drought – can therefore disrupt the production and supply of these fuels.

Such a disruption occurred during the 2012 drought. In July 2012, CNN Money reported

> One of the worst droughts in U.S. history is hampering oil production... [the energy] boom is possible partly by hydraulic fracturing.
>
> [It requires] lots of water. Each shale well takes between two and 12 million gallons of water to frack. That's 18 Olympic-sized swimming pools worth of water per well.[44]

In August 2012, CNN Money reported that the drought was hurting oil-fracking production.

> The drought is affecting energy production in West Texas, North Dakota, Kansas, Colorado and Pennsylvania, states in which hydraulic fracturing, also known as fracking, has become popular.[45]

Superstorm Sandy and other severe storms disrupt electricity reliability
Too much water (and wind) can also disrupt electricity transmission. The combination of Superstorm Sandy followed by a Nor'easter severely disrupted electricity service in the northeast. According to the Department of Energy, 8.6 million customers experienced electricity outages from the storms.[46] The bulk of the outages were in New Jersey, where 10 percent of all customers (383,143) still didn't have power at least one week after the storm.[47] It took until early December for the restoration of power to all customers.[48]

We must act to ensure reliability of our electricity generation and transmission
The National Climate Assessment draft predicts that future clime change related events will interfere with electricity transmission.

> Electricity is essential to power multiple systems, and a failure in the electrical grid can affect water treatment, transportation services, and public health. These infrastructure systems – lifelines to millions – will be affected by various climate-related events and processes.[49]

Reliable electricity generation and transmission is threatened by extreme weather linked to climate change. Therefore, policies that attempt to enhance reliability of the electricity system *cannot* ignore the impacts of climate change.

Policies to achieve a more secure, reliable electricity system must accomplish three goals.

- Slow climate change by reducing carbon pollution from power plants, the largest uncontrolled source of emissions.
- Provide financial incentives for innovative energy efficiency and no or low carbon electricity technologies, which would reduce reliance on dirty fossil fuels responsible for climate change.
- Enhance the resilience of the electricity infrastructure to extreme weather, sea level rise, and other impacts of climate change.

3. Reduce climate pollution from power plants

Power plants are the largest source of climate pollution
Electricity generation is the largest domestic contributor to climate change, responsible for more than one-third of the greenhouse gas pollution in the U.S. in 2011.[50] Society bears the cost of this carbon pollution from power plants due to the effects of climate change. Meanwhile, there is no cost to the power companies that emit carbon pollution since it is uncontrolled – it is essentially free to them. These companies have no economic incentives to reduce this threat to the climate. This market failure must be corrected by requiring power plants to significantly reduce their carbon pollution.

Strong public support for power plant pollution reductions

As previously noted, Americans understand that the impacts of climate change include extreme weather. They also strongly support government action to reduce carbon pollution responsible for climate change. A *USA Today* poll from February 2013 found that "84% of Americans say climate change is definitely or probably occurring; 64% favor regulating greenhouse gas emissions to fix problem."[51]

A poll released at the beginning of 2013 by the Yale and George Mason Universities' climate communications programs also found strong support for setting carbon pollution reduction standards.[52] Highlights of the poll include the following findings.

> Across party lines, there is support for taking action to reduce global warming, with pluralities of all groups favoring medium-scale efforts. Even among Republicans, a sizeable majority support making some effort to address global warming.
>
> Policies to promote renewable energy are favored by the majority of voters across party lines. Majorities support eliminating federal subsidies to the fossil fuel industry, but oppose ending subsidies to the renewable energy industry.
>
> Registered voters support regulating carbon dioxide as a pollutant.[53]

A poll by the Benenson Strategy Group for the League of Conservation Voters reiterated strong public support for action. After hearing both sides of the debate, Benenson found that "support remains strong even in the face of opposition attacks. After hearing this messaging from both sides, 65% still say they support the President taking significant action right now."[54]

Major utilities testify in favor of carbon pollution reductions to address climate change

On March 5, 2013, senior representatives from three major utilities testified before this subcommittee, and they agreed that action was necessary to reduce carbon pollution from power plants to curb climate change. In response to questions, witnesses from American Electric Power, Entergy, and Xcel all favored carbon pollution reductions.[55]

Mr. Mark McCullough, Executive Vice President of American Electric Power, said that "We do support a legislative approach [to carbon pollution reductions' over a regulated approach, and depending upon the details, would be very supportive."[56]

Mr. William M. Mohl, President of Entergy Wholesale Commodities, also endorsed carbon pollution reductions from the utility industry, preferably with a price signal. He noted that "We support some type of market-based price signal that puts a price on carbon emissions...We believe that that provides the incentive to develop new, cleaner technologies."[57]

Mr. Benjamin Fowke, Chief Executive Officer of Xcel, noted that "regulatory uncertainty" about utility carbon pollution reductions makes it more difficult for companies to plan their future investments.[58]

Government can adopt pollution limit legislation, carbon tax, and the Clean Air Act to reduce power plant pollution

There are several ways to reduce carbon pollution from power plants. Congress could pass a law establishing carbon pollution limits for power plants and other major sources. The House of Representatives passed the bipartisan American Clean Energy and Security Act in 2009, but the Senate was unable to muster 60 votes necessary to pass a companion bill.[59]

Alternatively, Congress could pass a progressive carbon tax to be levied on every ton of pollution from large power plants (and other major emitters).[60] If the price was set at an effective level, power plants and other big emitters would have an economic incentive to reduce their pollution. This system would also raise billions of dollars of revenue that could offset a reduction in payroll taxes, support investments in clean power, and/or reduce the deficit. Both conservative and progressive nongovernmental organizations have endorsed a carbon tax. Hopefully, Congress will enact such a tax as part of comprehensive tax reform or a budget deficit reduction plan.

In the absence of Congressional action, President Obama has the authority and obligation under the Clean Air Act to set a carbon pollution standard for existing power plants and other major emitters. In 2007 the Supreme Court ruled in *Massachusetts v. EPA* that greenhouse gases are pollutants under the Clean Air Act, and as such, the agency's administrator must consider whether these pollutants "may reasonably be anticipated to endanger public health or welfare."[61] If the administrator finds that this is the case, the EPA has the authority to limit pollutant emissions.

After the decision, EPA scientists conducted an assessment of the public health and welfare impacts of carbon and other climate change pollutants, and concluded that these emissions endangered the public. Agency Administrator Stephen Johnson wrote a January 2008 memo to President Bush stating, "Your Administration is compelled to act on this issue under existing law."[62] The president ignored this recommendation.

In December 2009, EPA Administrator Lisa Jackson adhered to the recommendation of agency scientists and finally made the endangerment finding for six major greenhouse gases, including carbon dioxide. [63] Jackson noted that the "impact on morbidity and mortality associated with higher temperatures" provided support for "a public health endangerment finding."[64]

EPA should set carbon pollution standard for existing power plants

After lengthy consultation with large numbers of stakeholders, the EPA proposed a carbon pollution standard for new power plants in March 2012.[65] Since power plants are designed to last for at least 50 years, this rule would effectively prevent the construction and operation of new coal-fired plants that don't incorporate carbon pollution capture and storage, therefore ensuring that we will not build the next generation of uncontrolled coal-fired power plants that would further worsen climate change.

There was overwhelming public support for the new power plant rule. Americans submitted 3.2 million comments in favor of limiting carbon pollution for both new *and* existing power plants—a record number for the agency.[66]

The agency was supposed to finalize the carbon pollution standard for new power plants by mid-April, thought it missed that deadline. It is important that EPA finalize this standard, so that it can develop and propose a standard for existing power plants.

A carbon pollution standard for existing power plants would require emissions reductions from roughly 600 existing coal-fired power plants.[67] These plants would probably employ some combination of fuel-switching to natural gas or co-firing with biomass; demand reduction via energy efficiency measures; and development of clean, renewable electricity generation.

The Natural Resources Defense Council, (NRDC) an environmental advocacy organization, released a plan to unlock the Clean Air Act's potential to curb carbon pollution from existing power plants. The plan would cut emissions from existing power plants by 26 percent by 2020. It would create a flexible approach for states and power plants to meet carbon pollution levels.

The plan achieves climate protection and public health benefits, grossing between $26 billion and $60 billion in 2020 for a net benefit between 6 times and 15 times more than the cost of the cleanup. There would also be no disruption in power supply even as emissions decline.[68]

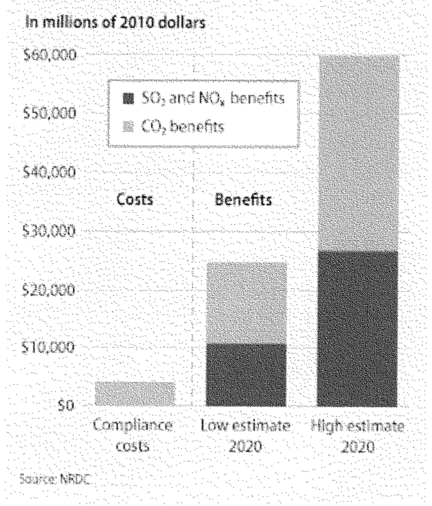


FIGURE 1
Estimated costs and benefits from reductions in SO_2, NO_x, and CO_2 (2020)

Reducing power plant pollution will have little impact on electricity reliability

Many opponents of pollution reduction requirements for power plants claim that they will reduce electricity reliability. This ignores recent history where several studies found that most "grid disturbances" were due to storms, tornadoes, cold, fire and other weather related events.[69] There appears to be little evidence of this occurrence.

The most recent false reliability claims were made about the Mercury Air Toxics Standard (MATS) for power plants. There is little evidence that reducing these dangerous pollutants by 90 percent would impair reliability. A Department of Energy study on this claim concluded that

> EPA rules will not create resource adequacy issues.
>
> To the extent that any localized reliability issues arise as the power sector adjusts to these rules, flexibility mechanisms in the Clean Air Act exist to ensure that any issues could be fully addressed before electricity delivery would be affected.[70]

Commissioner John R. Norris of the Federal Energy Regulatory Commission testified before this Subcommittee in 2011 that MATS would not make our electricity system less reliable. He said

> With the information we have in hand and the tools available to mitigate any potential reliability concerns, I believe we can manage the integration of these new environmental requirements into the power system while maintaining a reliable electric grid.[71]

In 2012, the Congressional Research Service came to the same conclusion, determining that

> Although the rule may lead to the retirement or derating of some facilities, almost all of the capacity reductions will occur in areas that have substantial reserve margins.
>
> To address the reliability concerns expressed by industry, the final rule includes provisions aimed at providing additional time for compliance if it is needed to install pollution controls or add new capacity to ensure reliability in specific areas. As a result, it is unlikely that electric reliability will be harmed by the rule.[72]

The standard to reduce carbon pollution from existing power plants would certainly include similar safeguards, and pose no threat to reliability. As noted earlier, the evidence suggests that climate related extreme weather poses a much greater threat to utility operations.

Reducing power plant carbon pollution will have little impact on electricity rates

Undoubtedly, opponents of reducing carbon pollution to fight climate change will claim that a power plant standard would lead to sky-rocketing electricity prices. Modeling conducted for NRDC by ICF International using the Integrated Planning Model (IPM®) used by EPA, combined with NRDC assumptions, found that this plan would *reduce* wholesale power prices primarily because a major portion of the carbon pollution cuts would occur from energy efficiency measures that *reduce* the use of electricity. The analysis predicts that retail electricity prices would remain about the same, while families' electricity bills would decline because they would use less electricity due to efficiency measures.[73]

Past utility industry predictions were wrong about high cost of pollution reductions
Industry sponsored studies frequently attempt to estimate the future cost of pollution reductions, and predict that cutting pollution will cause huge hikes in electric rates, reductions in jobs, and all sorts of other economic havoc. However, similar predictions about the acid rain control program for power plants were completely wrong.

In the late 1980's EPA studied the proposal to reduce the sulfur and nitrogen pollution from power plants responsible for acid rain. It predicted that the "annual cost of the program was expected to be $2.7 billion – 4.0 billion."[74]

The utility industry predicted that the cost of acid rain controls would be even higher – and it was even more wrong. For instance, a study for the Edison Electric Institute (EEI) predicted

> That the acid rain provisions alone of H.R. 3030 could cost electric utility ratepayers $5.5 billion annually between enactment and the year 2000, increasing to $7.1 billion per year from 2000-2010. These estimates were developed in an analysis conducted by Temple, Barker & Sloane.[75]

Yet an EPA analysis a decade later determined that the actual cost of cutting sulfur emissions by 40 percent was substantially lower—"$1 to $2 billion per year, just one quarter of original EPA estimates."[76]

4. Invest in efficiency, clean energy alternatives

Federal investments in emerging clean energy technologies less than fossil fuels investments
The U.S. has a long history of providing financial assistance to new energy technologies. A DBL Investors analysis, "What Would Jefferson Do?" determined that oil and gas received $442 billion in tax breaks and subsidies over the past 90 years, while renewable energy received only $5.6 billion over the past 15 years.[77] This is $80 invested in oil and gas production for every $1 invested in renewable electricity. Some of the fossil fuel tax breaks, such as the deduction for intangible drilling costs for oil companies, are nearly 100 years old.[78]

A 2011 study by Management Information Services Inc. for the Nuclear Energy Institute found that natural gas and coal received $121 billion and $104 billion, respectively, in government support from 1950-2010. Meanwhile, wind, solar, and ethanol received only $74 billion over this same time period.[79]

Summary of Federal Energy Incentives 1950-2010

	Oil	Natural Gas	Coal	Hydro	Nuclear	Renewables including ethanol	Geothermal	Total received, billions of 2010 $
Total received, billions of 2010 $	$369	$121	$104	$90	$73	$74	$7	$837
Share	44%	14%	12%	11%	9%	9%	1%	

Source: Management Information Services Inc.[80]

The Environmental Law Institute conducted a similar study, "Estimating U.S. Government Subsidies to Energy Sources: 2002-2008." It concluded that nearly $6 in federal government energy subsidies went to "traditional fossil fuels" for every $1 for "traditional renewables" (excluding biofuels). [81]

The American Recovery and Reinvestment Act provided boost to emerging clean energy technologies

The American Reinvestment and Recovery Act included $23 billion for wind, solar and geothermal power to help these industries become more cost competitive.[82] These investments helped the U.S. double renewable electricity generation in four years. In addition, the Production Tax Credit for wind power and the Investment Tax Credit for solar power also create incentives to invest in these emerging technologies.

These efforts are working. *Bloomberg New Energy Finance* reports that "the levelized costs of electricity for renewable technologies have plummeted" in the U.S.[83] Wind power is a major electricity generator in the U.S. Iowa produces nearly 20 percent of its electricity from wind.[84] Texas leads the nation in overall wind electricity generation, and was the first state to reach 10,000 megawatts of wind energy installation.[85]

The Energy Information Administration reports that new wind energy is cheaper than a new conventional coal plant, new advanced nuclear plant, or new natural gas fired combustion turbine.[86]

Solar power, too, is becoming much more affordable and prevalent. The Solar Energy Industry Association reported in January 2013 that the cost of a solar electricity system has dropped and deployment has grown

> More solar capacity was installed in the first three quarters of 2012 than in all of 2011. The industry expects to have installed more than one gigawatt of solar in the fourth quarter of 2012 alone, while in 2010 we installed 852 megawatts for the entire year. And we expect 2013 will be another year of record growth for our industry.[87]

Other nations powered by renewable electricity

Other countries also found that renewable electricity is cheaper than fossil fuel power. *Bloomberg New Energy Finance* just reported that in Australia "wind energy is 14% cheaper than new coal and 18% cheaper than new gas."[88]

Germany reported that "all renewable energies combined accounted for about 26 percent of electricity production over the first nine months" of 2012.[89] In 2012 "solar power's share in the country's [Germany] electricity production rose to 6.1 percent from 4.1 percent."[90] This occurred even though Germany receives less sunlight than anywhere in the U.S. except for Alaska.[91]

Portugal's electricity network operator recently announced that renewable energy supplied 70 percent of total consumption in the first quarter of this year. Portuguese citizens are using less energy and using sources that never run out for the vast majority of what they do use.[92]

Policies to increase investments in clean energy

There are several primary ways that the government invests in clean energy: direct spending, tax incentives, and credit support through loans and loan guarantees. Public market financing provides a fourth means. A comprehensive clean energy investment program will utilize all four tools, recognizing that each one meets specific needs. A progressive carbon tax could provide the funds to be invested in new energy technologies. These tools are:

Direct spending: The government should provide direct support of $9 billion per year for research and development in both the public and private sector. In the public sector, this should be continued mainly through the Department of Energy and its affiliated labs. The Advanced Research Projects Agency–Energy (ARPA-E) program, which invests in private sector research, should be strengthened by doubling its funding. The proposed $9 billion in research funding would return us to the peak level of government investment in energy R&D in the late 1970s (in real dollars).[93]

Tax incentives: The production tax credit for wind energy has been a huge driver for deploying clean energy at scale by leveraging at least $10 in private investment for every $1 in tax credits.[94] Thanks to this investment incentive, there is enough wind energy to power more than 13 million homes. This credit—set to expire at the end of 2013—should be extended for several years.[95]

Credit programs: The Department of Energy Loan Guarantee Program should be improved upon with a new Clean Energy Deployment Administration (or "Green Bank"), which would provide a range of financing tools to enable clean energy deployment.[96]

Public market financing tools: Ultimately, we need to finance clean energy just like we finance traditional energy: through public equities and corporate debt. There are multiple ways to encourage this, but the most likely is to adapt master limited partnerships and real estate investment trusts to meet the needs of clean energy technologies.

Establish federal policies that increase demand for clean electricity

Increasing market demand for clean energy is essential to provide investors with more certainty about the return on their investment in emerging technologies. There are several policies that could accomplish this goal.

Twenty-nine states and the District of Columbia require their utilities to generate a designated portion of their electricity from wind, solar, geothermal, and other renewable energy sources.[97] These programs encouraged investments in clean power sources and helped to nearly double nationwide renewable electricity generation over the past four years.[98]

Despite some utility industry and other special interest claims, these renewable electricity standards appear to have no pattern on their impact on utility rates. Richard Caperton, Managing Director of the energy program at the Center for American Progress, analyzed the "the average annual electricity rate change in states with these standards, compared to the average for states without these standards." (see table below) He concluded that

> State renewable energy standards have no predictable impact on electricity rates. Even using an approach that attempts to isolate these standards from other factors driving rate changes, there's simply too many other factors.[99]

Congress could enact a similar clean energy standard that would require utilities to produce 80 percent of their electricity from no- or low-carbon sources by 2035.[100] It is essential that a clean energy standard require that at least 35 percent of the total electricity generation in 2035 come from renewables and efficiency measures so as to provide certainty about the market demand for clean energy.[101]

President Obama provided a boost to clean energy investments with an executive order to require that federal agencies become more sustainable. Executive Order 13514 directs "Federal agencies to reduce greenhouse gas pollution … and leverage Federal purchasing power to support innovation and entrepreneurship in clean energy technologies."[102]

The order sets a goal for agencies to "use at least 5 percent electricity from renewable sources."[103] Some agencies have already met this target, including the Department of Energy and the General Services Administration.[104] The administration should require all federal agencies to achieve this measure by 2014. Federal agencies should meet a 10-percent-renewable standard by 2017, and a 15-percent standard by 2020. This would notably increase demand for renewable electricity.

Use appropriate federal lands and waters to support clean-energy development

Federally owned real estate produces coal and natural gas used to generate electricity. Approximately 43 percent of all coal and 20 percent of natural gas currently produced in the United States comes from public lands or waters.[105] Despite the tremendous potential of clean energy production on federal property, only 1 percent of the country's wind electricity and practically none of its solar power come from public lands and waters.[106]

The Department of the Interior already met the president's goal of authorizing 10,000 megawatts of renewable energy on federally managed waters and lands.[107] The federal government should build on this success by implementing a "clean resources standard" for public lands and waters. This would require federal land and water management agencies to ensure that 35 percent of the electricity from resources on public lands is clean and renewable—from wind, solar, geothermal, biomass, and small hydropower.[108]

When done responsibly, electricity generation is an appropriate use for many public places. It is important, however, that any energy development on public lands avoid sensitive areas, employ the most modern technology, and be in full compliance with environmental laws.

The integration of renewable electricity technologies should have no impact on reliability
The North American Electric Reliability Corporation "State of Reliability 2013" report found that "bulk power system reliability remains adequate."[109] It also found that variable power sources – such as wind turbines – have had no impact on reliability. It concluded

> There were no significant reliability challenges reported in the 2011/2012 winter and the 2012 summer periods resulting from the integration of variable generation resources. More improved wind forecast tools and a wind monitoring displays are being used to help system operators manage integration of wind resources into real-time operations.[110]

5. Increase the resilience of electricity infrastructure

Investments in community resilience save money
Many communities are undertaking efforts to make their buildings, shelters, water treatment, electricity, roads, and other vital infrastructure more resilient to damage from extreme weather. Such efforts are expensive, particularly for cash-strapped communities and states that are still recovering from the Great Recession. But making these investments can help save money in the future, when storms, floods, heat waves, droughts, and wildfires will become more frequent and/or more devastating. The Federal Emergency Management Agency, or FEMA, estimates that "a dollar spent on [pre-disaster] mitigation saves society an average of $4" in lower damages.[111]

After a devastating flash flood in 1984, for example, Tulsa, Oklahoma, crafted a resilience program to control flood damages by relying on natural systems and other methods to improve water drainage. The Tulsa city government reports that "Since the City adopted comprehensive drainage regulations 15 years ago; we have no record of flooding in any structure built in accord with those regulations."[112]

Napa County, California, created a flood-control-protection project to limit flood damage. The project is paid for in part by passing a half-cent local sales-tax increase to fund the local share of this project. The project's goal is to achieve "a savings of $26 million annually in flood damage costs."[113]

It is imperative that the federal government provides technical and financial assistance to the most at-risk communities; such efforts are an excellent economic investment. Because the federal government pays for a major share of disaster recovery, investing in resiliency now will help protect taxpayers from more deficit spending in the future.

The federal government invests less in community resilience

Despite the myriad benefits of investments in community resilience, federal assistance for resilience, or "pre-disaster mitigation," has actually declined over the past decade.[114] Rep. Lois Capps, her Energy and Commerce Committee colleagues Henry Waxman, Ed Markey, Eliot Engel, Doris Matsui, John Sarbanes, and 34 additional representatives wrote a letter to President Barack Obama in February urging him to appoint a blue-ribbon panel that would:

> Develop a comprehensive plan to help local communities prepare for the anticipated impacts of increased climate-related extreme weather.
>
> Estimate the financial support necessary for communities to develop and implement plans to increase their resilience to floods, severe storms, droughts, heat waves, sea level rise, wildfires, and day-to-day economic impacts.
>
> Identify federal programs that already provide funding for resilience efforts.
>
> Recommend a dependable revenue stream to provide additional resources for local pre-disaster mitigation planning.[115]

The Obama administration should adopt Rep. Capp's proposal.

The administration's proposed FY 2014 budget has an enhanced focus on community resilience. The budget:

> Includes $200 million for "Climate Ready Infrastructure" that build enhanced preparedness to extreme weather and other impacts of climate change in their planning efforts, and that have proposed or are ready to break ground on infrastructure projects to improve resilience.
>
> These investments will support a broader Administration commitment to help communities become more resilient through direct technical assistance, provision of useful data and tools on projected impacts, and support for planning.[116]

In addition, technical-assistance grants for community-resilience projects are available through the Department of Housing and Urban Development's Sustainable Communities program. These programs are an important start, but they provide only a small amount of the revenue that is essential for building more resilient communities across the nation.

Congressional Research Service recommendations for utility resilience

Last August, the Congressional Research Service issued "Weather-Related Power Outages and Electric System Resiliency." It included a number of valuable recommendations that would increase the resilience of utilities' transmission network.

> Suggested solutions for reducing impacts from weather-related outages include improved tree trimming...placing distribution and some transmission lines underground, implementing Smart Grid improvements to enhance power system operations and control, inclusion of more distributed generation, and changing utility maintenance practices and metrics to focus on power system reliability.[117]

In addition, CRS had some recommendations for Congress to help reduce the likelihood and length of extreme weather related power outages. We urge the Subcommittee to give these recommendations serious consideration.

> A number of options exist for Congress to consider which could help reduce storm-related outages. These... [include] greater strategic investment in the U.S. electricity grid. Congress could empower a federal agency to develop standards for the consistent reporting of power outage data.
>
> Many distribution systems are in dire need of upgrades or repairs. The cost of upgrading the U.S. grid to meet future uses is expected to be high, with the American Society of Civil Engineers estimating a need of $673 billion by 2020. While the federal government recently made funding available of almost $16 billion for specific Smart Grid projects and new transmission lines under the American Recovery and Reinvestment Act of 2009, there has not been a comprehensive effort to study the needs, set goals, and provide targeted funding for modernization of the U.S. grid as part of a long-term national energy strategy.[118]

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[115] Office of Rep. Lois Capps, "Capps, Pallone, Waxman, and 37 Colleagues Urge President Obama to Appoint Blue Ribbon Panel To Evaluate Climate Change Preparedness," Press release, February 11, 2013, available at http://capps.house.gov/press-release/capps-pallone-waxman-and-37-colleagues-urge-president-obama-appoint-blue-ribbon-panel.
[116] Office of Management and Budget, "Building a Clean Energy Economy, Improving Energy Security, and Addressing Climate Change," available at http://www.whitehouse.gov/omb/budget/factsheet/building-a-clean-energy-economy-improving-energy-security-and-addressing-climate-change (last accessed April 2013).
[117] Richard J. Campbell, "Weather-Related Power Outages and Electric System Resiliency."
[118] *Ibid.*

Mr. WHITFIELD. Thank you, Mr. Weiss.
And Mr. Gramlich, you are recognized for 5 minutes.

STATEMENT OF ROBERT GRAMLICH

Mr. GRAMLICH. Thank you, Chairman Whitfield, Ranking Member Rush and subcommittee members. It is a pleasure to be here today on behalf of America's wind industry. The American Wind Energy Association represents over 1,200 member companies, including project developers, manufacturers and service providers. Wind energy production has grown dramatically in recent years, lowering energy costs for consumers while keeping the grid reliable.

Over the past 5 years, wind energy has accounted for more than 35 percent of all new electric generating capacity in the U.S. Last year alone, $25 billion in private investment went into building new U.S. wind projects, providing 80,000 American jobs. The wind industry now has 550 manufacturing facilities in 44 states and wind projects in 39 states and Puerto Rico. Nearly 70 percent of the content used in U.S. wind turbines is produced here in America now, up from 25 percent just a few years ago.

Last year, wind energy reliably provided more than 20 percent of the electricity in Iowa and South Dakota, and more than 10 percent of the electricity in nine states. At times, wind energy has reliably provided more than 55 percent of the electricity on the main utility system in Colorado and 35 percent on the main grid in Texas.

Dozens of studies by independent grid operators and utilities have examined wind energy's impact on electric reliability and all have concluded that our use of wind energy can increase many times over without any negative impacts on reliability.

Since the days of Thomas Edison, grid operators have had to constantly adjust the output of power plants to respond to fluctuations in electricity demand and the sudden failures of large conventional power plants. All energy sources underperform from time to time and no power plant operates predictably 100 percent of the time. The lights stay on because all power plants have always backed up—been backed up by all other power plants. Wind energy follows the same market rules as other resources, pays for any costs it causes and only gets paid for the services it provides.

Compared to wind energy, changes in electricity demand and failures at conventional power plants are far larger contributors to grid variability and the need for the flexible reserves or backup that grid operators use to keep supply and demand in balance. Grid operators that use efficient practices have found that they can reliably add large amounts of wind energy with virtually zero need for backup power beyond what is already needed.

Even if power—even if additional reserves are needed, it is much cheaper to accommodate the slow and predictable variations in wind output than the instantaneous loss of conventional power plants that can occur at any time. Data from the Texas grid operator indicates that the additional cost of reserves for obtaining almost 10 percent of its electricity from wind energy accounts for about 6 cents out of a typical household's $140 monthly electric bill. A study by utilities in Nebraska that the whole region reliably obtained 40 percent of its electricity from wind energy at an additional reserves cost of around 80 cents per monthly bill. In contrast, data indicates that the cost of reliably accommodating instantaneous outages at other power plants is 40 times higher, at around $2.50 per monthly bill.

These reserves' costs are a small fraction of the benefits wind energy provides for consumers. Wind energy drives down electricity prices by displacing higher cost, less efficient power plants. Wind energy also provides the stability of a long-term fixed energy price, which is offered by very few other energy sources. This protects consumers from fluctuations in fuel prices, much like a fixed-rate mortgage protects homeowners from interest rate spikes.

Utilities understand that wind energy is a good deal for their customers. At least 74 utilities bought or owned wind power in 2012, up 50 percent from a year ago. The Southern Company recently made its third wind energy purpose, explaining that wind energy reduces its customers' electric bills. Similarly, Oklahoma Gas and Electric estimates that a single wind project will save Arkansas customers $46 million.

Finally, the Colorado Public Utilities Commission found that a single wind purchase by Xcel Energy, quote, "will save rate payers $100 million," unquote, while providing the opportunity to lock in a price for 25 years. In short, wind energy is playing a critical role in providing American homes and businesses with reliable homegrown and low-cost energy.

Thank you for inviting me, and I look forward to answering your questions.

[The prepared statement of Mr. Gramlich follows:]

Testimony of Rob Gramlich, Interim CEO, American Wind Energy Association

House Committee on Energy and Commerce
Subcommittee on Energy and Power

Hearing on American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape

May 9, 2013

Thank you Chairman Whitfield, Ranking Member Rush, and Subcommittee Members. It is a pleasure to be here today on behalf of America's wind industry. The American Wind Energy Association represents over 1,200 member companies, including project developers, manufacturers, and service providers.

Wind energy production has grown dramatically in recent years, lowering energy costs for consumers while keeping the grid reliable. Over the past five years, wind energy has accounted for more than 35 percent of all new electric generating capacity in the U.S. Last year alone, $25 billion in private investment went into building new U.S. wind projects, providing 80,000 American jobs. The wind industry now has 550 manufacturing facilities in 44 states, and wind projects in 39 states and Puerto Rico. Nearly 70% of the content used in U.S. wind turbines is produced here in America, up from 25% just a few years ago.

Last year, wind energy reliably provided more than 20% of the electricity in Iowa and South Dakota, and more than 10% of the electricity in nine states. At times, wind energy has reliably provided more than 55% of the electricity on the main utility system in Colorado, and 35% on the main grid in Texas.

Dozens of studies by independent grid operators and utilities have examined wind energy's impact on electric reliability, and all have concluded that our use of wind energy can increase many times over without any negative impacts on reliability.[1] This is possible because the grid takes power from many sources that vary over time, just like the Mississippi River takes water from many tributaries and keeps a steady flow into the Gulf of Mexico.

Since the days of Thomas Edison, grid operators have had to constantly adjust the output of power plants to respond to fluctuations in electricity demand and the sudden failures of large conventional power plants. The grid operator does not care if you turn on electric appliances because that is almost always canceled out by someone else turning theirs off. Similarly, changes in output at one wind plant are almost always canceled out by an opposite change somewhere else on the grid, sometimes at another wind plant. In some regions, such as coastal areas, wind output is typically highest when electricity demand is highest.[2] Because wind turbines are spread across a large area, it typically takes many hours for a weather event to affect a large share of a region's wind output. Moreover, weather forecasting makes these changes predictable.

[1] http://www.uwig.org/opimpactsdocs.html

[2] For example, analysis by the Texas grid operator indicates that all of the typical energy output of the state's approximately 2,000 MW of coastal wind energy plants can be relied on for providing dependable capacity to meet electricity demand, "due to the increased coastal winds that occur in summer afternoon." http://www.ercot.com/content/news/presentations/2013/ERCOT%20Loss%20of%20Load%20Study-2013-PartII.pdf

All energy sources underperform from time to time, and no power plant operates predictably 100% of the time.[3] The lights stay on because all power plants have always been backed up by all other power plants. Wind energy follows the same market rules as other resources, and only gets paid for the services it provides.

Compared to wind energy, changes in electricity demand and failures at conventional power plants are far larger contributors to grid variability and the need for the flexible reserves, or backup, that grid operators use to keep supply and demand in balance.[4] Grid operators that use efficient practices have found that they can reliably add large amounts of wind energy with virtually zero need for backup power beyond what is already needed.[5] Even if additional backup is needed, it is much cheaper to accommodate the slow and predictable variations in wind output than the instantaneous loss of conventional power plants that can occur at any time.

Data from the Texas grid operator indicate that the additional cost of backup for obtaining almost 10% of its electricity from wind energy accounts for about six cents out of a typical household's $140 monthly electric bill.[6] In contrast, other data indicate that the cost of reliably

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[3] For example, in February 2011, around 50 conventional power plants in Texas abruptly failed in the cold, while wind energy earned accolades from the grid operator for helping to keep the lights on. http://www.texastribune.org/2011/02/04/an-interview-with-the-ceo-of-the-texas-grid/

[4] As an illustration, one can look at data from PJM, the grid operator for parts of 13 Mid-Atlantic and Great Lakes states and the District of Columbia. Over the last year, the largest hourly changes in electricity demand were more than ten times larger than the largest hourly changes in wind energy output, even though PJM has over 6,000 MW of wind energy on its system. http://www.pjm.com/~/media/committees-groups/task-forces/irtf/20130417/20130417-item-05-wind-report.ashx, http://www.pjm.com/markets-and-operations/energy/real-time/loadhryr.aspx

[5] http://www.uwig.org/san_diego2012/Navid-Reserve_Calculation.pdf

[6] Based on a calculated wind integration cost of $0.50 per MWh of wind energy, which equals $.046 per MWh of total load served in ERCOT at 9.2% wind energy use (http://www.uwig.org/slcforework/Ahlstrom-Session1.pdf),

accommodating instantaneous outages at other power plants is forty times higher, at around $2.50 per monthly bill.[7] A study by utilities in Nebraska calculated that the whole region could reliably obtain 40% of its electricity from wind energy at an additional backup cost of around 80 cents per monthly bill.[8]

These costs are a small fraction of the benefits wind energy provides for consumers. Wind energy drives down electricity prices by displacing higher cost, less efficient power plants.[9] Second, wind energy offers the stability of a long-term fixed energy price, which is offered by

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based on reserve data presented by David Maggio, ERCOT (http://www.uwig.org/San_Diego2012/Maggio-Reserve_Calculation_Methodology_Discussion.pdf), multiplied by the 1.262 MWh used per month by the average Texas household (http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf)

[7] $2/MWh of total load served (http://www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf, page 61), multiplied by the 1.262 MWh used per month by the average Texas household

[8] http://www.uwig.org/ne_study.pdf

[9] While wind energy does drive down electricity market prices, this impact is not caused by the wind production tax credit (PTC). While the PTC is important for facilitating wind energy development, the PTC has no direct impact on electricity market prices except under extremely rare and isolated circumstances. With or without the PTC, wind energy enters the electricity market with one of the lowest operating costs because it has no fuel costs, and grid operators use wind energy to displace the power plants with the highest operating costs. Both wind and nuclear energy drive electricity market prices down because their low fuel and operating costs allow them to displace more expensive forms of generation, not because of the incentives they receive. Even though both wind and nuclear energy receive incentives, there is no merit to the argument that these incentives negatively affect the economics of other generators. That is because neither wind nor nuclear energy sets the clearing price in electricity markets except under extremely isolated circumstances, so these incentives are not reflected in the market clearing price that all generators see. For example, in ERCOT, the power system that has by far seen the most instances of wind energy setting a localized market clearing price, wind energy set the marginal electricity price for only 2% of price points in 2011. The impact on conventional generators was even more limited because those instances were confined to ERCOT's West zone, which contains only 5% of ERCOT's conventional generation. Moreover, those already isolated instances will be virtually eliminated when long-needed transmission upgrades are completed by the end of 2013. To sum up, even though both wind and nuclear energy receive incentives, those incentives have virtually zero direct impact on investment or operational decisions for other power plants because neither resource sets the electricity market clearing price outside of extremely rare occurrences in isolated pockets on the grid.

very few other energy sources. This protects consumers from fluctuations in fuel prices much like a fixed rate mortgage protects homeowners from interest rate spikes.[10]

Synapse Energy Economics is releasing a report today that indicates doubling the use of wind energy in the Mid-Atlantic and Great Lakes states would save consumers a net $2.6 billion per year.[11] Similarly, the New England grid operator calculated that obtaining 20% of the region's electricity from wind would reduce electricity prices by more than 10%.[12] Numerous other studies confirm that finding.[13]

Utilities understand that wind energy is a good deal for their customers. At least 74 utilities bought or owned wind power in 2012, up 50% from a year ago. Southern Company recently made its third wind energy purchase, explaining that wind energy reduces its customers' electric bills.[14] Similarly, Oklahoma Gas and Electric estimates that a single wind project will save Arkansas customers $46 million.[15] Finally, the Colorado Public Utilities Commission found

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[10] http://emp.lbl.gov/publications/revisiting-long-term-hedge-value-wind-power-era-low-natural-gas-prices
[11] Synapse Energy Economics, "The Net Benefits of Increased Wind Power in PJM," to be released on May 9, 2013. The study found $2.6 billion in net annual benefits from doubling wind energy production beyond existing requirements, after accounting for all wind costs and without even accounting for the value of reduced pollution.
[12] http://www.uwig.org/newis_es.pdf
[13] http://www2.illinois.gov/ipa/Documents/April-2012-Renewables-Report-3-26-AAJ-Final.pdf, http://www.mass.gov/eea/docs/doer/publications/electricity-report-jul12-2011.pdf, http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/MeritOrder.pdf, http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/BC/Energy_and_Environment/files/Southwest%20Power%20Pool%20Extra-High-Voltage%20Transmission%20Study.pdf, http://www.synapse-energy.com/Downloads/SynapseReport.2012-08.EFC.MISO-T-and-Wind.11-086.pdf, http://www.nyserda.ny.gov/Publications/Program-Planning-Status-and-Evaluation-Reports/~/media/Files/EDPPP/Energy%20and%20Environmental%20Markets/RPS/RPS%20Documents/rps-performance-report-2009.ashx
[14] http://www.georgiapower.com/about-us/media-resources/newsroom.cshtml, April 22, 2013 press release
[15] http://www.apscservices.info/pdf/12/12-067-u_2_1.pdf

that a single wind purchase by Xcel Energy "will save ratepayers $100 million" while providing the opportunity to "lock in a price for 25 years."[16]

In short, wind energy is playing a critical role in providing American homes and businesses with reliable, homegrown, low-cost energy.

Thank you for inviting me, and I look forward to answering your questions.

[16] Colorado Public Utilities Commission, Decision No C11-1291

Mr. WHITFIELD. Thank you.

Dr. Lesser, you are recognized for 5 minutes.

STATEMENT OF JONATHAN LESSER

Mr. LESSER. Thank you, Chairman Whitfield, Ranking Member Rush, members of the subcommittee. My name is Jonathan Lesser. I am the president of Continental Economics. I began my professional career almost 30 years ago as a load forecaster for Idaho Power. Over the years, in my work for government, industry, and as a consultant, I have been involved with and researched many facets of the energy industry as well as corresponding policy issues at both the national and individual state levels.

I appreciate your invitation to be here today to discuss the reliability challenges confronting us as we seek to integrate intermittent resources onto the grid. I am appearing today on my own behalf, and the views expressed in my testimony today are mine and mine alone.

Integration costs can be broken down into two categories. The first category includes the cost of ensuring the power system is operated safely and reliably from moment to moment.

The second category includes the cost of connecting resources to the power grid, called interconnection cost, specifically building new transmission lines and substations to deliver electricity from individual generating units to load centers like D.C.

To operate a power system, the supply of electricity must continuously match demand. If power supply exceeds demand at any time, it can overload the system. If demand exceeds supply, you can have brownouts or even rolling blackouts. Because the overall demand for electricity changes moment to moment, power system operators must continually adjust electric supplies.

In addition, as has been mentioned, grid operators have to plan for contingencies. On those hot sultry August days here in Washington, D.C., the demand for electricity peaks because of air conditioning, so power system operators have to ensure there is sufficient resources to meet those loads.

Gas generators provide the most quick reserve capacity because they can be started, stopped or ramped up and down fairly easily and quickly. In contrast, coal and nuclear plants are designed to run around the clock, generating the same amount of power all times. Starting a nuclear plant, for example, can actually take several days. Although the output of these plants can be varied up and down, doing so increases the wear and tear on them, which increases their operating costs and reduces their fuel efficiency.

It is not surprising that intermittent resources, like wind and solar, cannot provide these sorts of operating reserves. In fact, intermittent resources actually increase the need for reserves. The reason for this is that system operators must also cope with the wide swings and output from intermittent resources. That, in a nutshell, is what integrating intermittent generating resources is all about and why it is both challenging and costly.

Chicago's experience during last July's heat wave provides a compelling example. During that heat wave, Illinois wind power generated less than 5 percent of its capacity during the record breaking heat, producing only an average of 120 megawatts of power from over 2,700 megawatts of installed wind. On July 6, 2012, when the demand for electricity in northern Illinois and Chicago hit a record of over 22,000 megawatts, the average amount of wind generation that day was a virtually non-existent 4 megawatts. The potential loss of thousands of megawatts of intermittent generation for a short time, which has occurred in the past, means that system operators must increase the quantity of available reserve capacity. That increases cost. It is as if thousands of vehicles have their engines idling, waiting to run on the possibility they are needed.

One such study, for example, by the American Tradition Institute, found reliability related transmission losses and costs for Texas alone are over $1 billion per year.

In regions with wholesale electric markets, system operators use next day forecasts of availability and demand to determine how they will operate the power system. Although even wind advocates acknowledge wind's inherent intermittency, they claim wind generation can be predicted accurately several days in advance, allowing system operators to reduce, if not eliminate, the impacts of wind's volatility. Forecasts and operational data, including—in areas including Texas as well as in European countries, show that is not the case.

The other thing about that that is causing this problem to be severe is that subsidies, such as the PTC and renewable portfolio standards, plus the socialization of most integration costs, have increased reliability concerns. As Commissioner Donna Nelson of the Texas Public Utility Commission stated last year, the market distortions caused by renewable energy incentives are one of the primary causes, I believe, of our current resource adequacy issues. This distortion makes it difficult for other generation types to recover their cost and discourages investment in new generation, and I will leave it at that.

Thank you very much. I look forward to your questions.

[The prepared statement of Mr. Lesser follows:]

CONTINENTAL ECONOMICS

BEFORE THE HOUSE ENERGY AND POWER SUBCOMMITTEE

"AMERICAN ENERGY SECURITY AND INNOVATION: GRID RELIABILITY CHALLENGES IN A SHIFTING ENERGY RESOURCE LANDSCAPE"

TESTIMONY OF

JONATHAN A. LESSER, PhD

CONTINENTAL ECONOMICS, INC.

MAY 9, 2013

SUMMARY

Federal and state policies that subsidize development of intermittent generating resources, especially wind generation, reduce the reliability of the power system because of the inherently volatile nature of the output of such resources.

To compensate for this reduced reliability, power system operators must increase reserves of fossil-fuel resources, primarily gas-fired generating plants, to compensate for the ups-and-downs of intermittent resource availability, including the potential loss of thousands of megawatts of generation from intermittent resources when conditions change (i.e., the wind stops blowing or the sun stops shining). These additional reserve requirements increase reliability-related integration costs, which are socialized across all customers. As more intermittent resources are built, they increase the severity of reliability issues and increase per megawatt-hour integration costs, as well as total integration costs.

Compounding these reliability problems are policies that socialize the costs to build of new high-voltage transmission lines needed to connect intermittent resources, especially wind generation. Because wind turbines require a lot of land per turbine, wind facilities are typically built in rural areas far from urban load centers, because land is so much cheaper. When wind turbines are built in these locations, new transmission lines must often be built to connect them to the power grid. And, because they are so far away from load centers, there are significant line losses, which reduce the actual amount of electricity delivered to customers. Moreover, wind generation, by far the largest intermittent resource, with over 60,000 megawatts of installed capacity, tends to produce the greatest amount of electricity when the demand for electricity is lowest (at night, and in spring and fall). As a result, wind power is exacerbating economic losses of traditional "baseload" generating units that are designed to run around-the-clock, and are a crucial element of providing reliable, low-cost electricity.

Subsidies, such as the wind PTC, plus socialization of reliability-related and transmission integration costs, means that intermittent generation developers pay only a small fraction of the true costs they impose on the electric system. This is having adverse economic impacts – causing traditional generation resources to retire prematurely because of artificial price suppression – and thus further exacerbating reliability issues, and suppressing new generation investment. Left unchecked, these subsidies for intermittent generation will reduce reliability, lead to higher electric prices, and reduce economic growth and job creation.

Therefore, I recommend that (1) To the extent possible, require <u>all</u> generators to pay for the reliability-related integration costs they cause, rather than socializing those cost across all electric consumers; and (2) Eliminate <u>all</u> subsidies paid to electric generators, whether they are intermittent resources or schedulable resources.

I. INTRODUCTION

Good morning. My name is Jonathan Lesser. I am the President of Continental Economics, Inc., an economic consulting firm specializing in energy and regulatory matters. I appreciate the invitation from the Committee to testify today regarding the costs and the reliability implications of integrating "intermittent" generating resources.

By way of background, I began my professional career almost 30 years ago, as a load forecaster for Idaho Power. In my work for government, industry, and as a consultant, I have been involved with, and researched, many facets of the electric industry, as well as corresponding policy issues, at both the national and individual state levels. These issues have covered: (1) the "nuts and bolts" issues involved in regulating and designing electric rates; (2) electric industry restructuring, and the introduction of wholesale and retail competition; (3) environmental regulations affecting energy resource development and use; (4) the costs and benefits of renewable generation; (5) the economic impacts of electric competition; and (6) the economic consequences of energy subsidies.

I have testified numerous times before state regulatory commissions, before the Federal Energy Regulatory Commission, before legislative committees in many other states, and before international energy regulators. I have co-authored three textbooks, including *Environmental Economics and Policy*, *Fundamentals of Energy Regulation* (for which my co-author and I are now preparing a second edition), and *Principles of Utility Corporate Finance*.

I am appearing before the Committee today on my own behalf and the views expressed in my testimony are mine alone.

My testimony this morning focuses on "intermittent" generating resources – primarily wind and solar photovoltaics (PV) – their impact on electric system reliability, and the costs that must be borne to "integrate" such resources onto the power grid.

In the next section of my testimony, I provide background information on what "integrating" these intermittent resources means in terms of how the power system operates. Next, in Section III, I explain why integrating intermittent resources is more costly than integrating traditional fossil, nuclear, hydroelectric, and, indeed, any generating resource that can be operated on a continuous basis. In Section IV, I discuss some of the "myths v. facts" associated with the costs of integrating intermittent resources. Section V offers my policy recommendations on how to address these resources to ensure that the overall reliability of our electric system is not compromised.

II. WHAT "INTEGRATION" OF INTERMITTENT RESOURCES MEANS

Intermittent power resources are defined as resources that cannot be scheduled to provide a known quantity of electric power at a given time. There are two primary categories of intermittent resources that are the focus of integration studies and reliability concerns: wind and solar PV power. Wind turbines, of course, can only generate electricity when the wind is blowing. Solar PV can only generate electricity when the sun is shining.

In contrast, fossil-fuel, nuclear, and hydroelectric power (with storage dams, such as Grand Coulee Dam on the Columbia River) can be scheduled. For example, barring the very low chance of a forced outage, a modern natural gas-fired combined-cycle generating unit will provide power around-the-clock, and can be ramped up or down quickly to meet the ever-changing demand for electricity. Similarly, the amount of power produced by a hydroelectric plant can be varied simply by changing the amount of water that flows through the turbines.

Integration costs can be broken down into two main categories. The first category includes the costs of ensuring the power system is operated safely and reliably from moment to moment. The second category includes the costs of connecting resources to the power grid, called "interconnection costs," specifically building new transmission lines and substations to deliver electricity from individual generating units to load centers.

Integration and Power System Reliability

To operate a power system, the supply of electricity must continuously match demand. If demand exceeds supply, voltage and frequency drops. For example, you may notice that, when the compressor motor in your refrigerator starts, the lights in your home dim slightly. When the compressor starts, the demand for electricity increases suddenly. This causes a momentary drop in voltage, which causes the lights to dim. If power supply exceeds demand, it can cause voltage levels to increase. If the voltage is too high for the lights in your home, they will burn out, because too much electricity is being delivered to it.

Because the overall demand for electricity changes from minute-to-minute, power system operators must continually adjust electric supply to maintain voltage and frequency within operating limits. If they don't, there will be a blackout. The constant changing of electric supply to match demand is called "load following." The most common method for load following is called "automatic generation control" or AGC. (It is also called "frequency reserve.") Today, AGC consists of computer software installed at certain generating plants whose output can be increased or decreased constantly in response to changing demand. Basically, what happens is that the AGC software increases or decreases the speed of a generating turbine: when demand increases, the turbine speed is increased, just like the engine in your car speeds up when you press on the accelerator; when demand decreases, the turbine speed is slowed.

In addition to needing to adjust electric supply to meet ever changing demand, power system operators have to plan for contingencies, in other words, unexpected events. For example, on those hot, sultry August days in Washington, DC, the demand for electricity peaks because of air conditioning load. Power system operators must ensure there are sufficient resources to meet that peak demand. If a generating plant breaks down unexpectedly on that same day, there must be enough reserve capacity to take up the slack. Thus, there must always be generating capacity held in reserve, either generating units that can be switched on quickly, mechanisms to reduce demand, such as reducing electric consumption at a large manufacturer, or both. And, in fact, in the regional power system that includes DC, called PJM, both types of reserves exist.

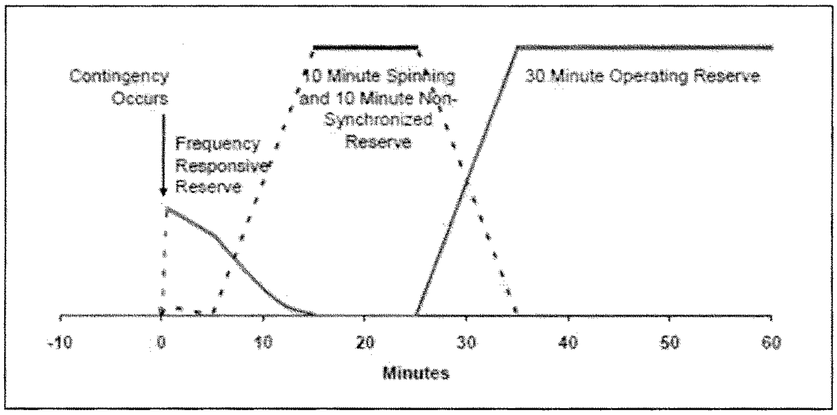
These additional reserves come in three different flavors: spinning, non-spinning, and operating reserves. Spinning reserves are generators that are running, but not connected to the grid. They are the electric equivalent of your car engine running, but the car is in neutral gear. If you need to move, all you have to do is put the car in gear (or press on the accelerator) and away you go.

Non-spinning reserve refers to generators that are not running, but can be brought on line very quickly, generally within 10 – 30 minutes. The vehicular analogy for non-spinning reserve is finding your keys, walking out to the car, starting the engine, and driving off. You can do it relatively quickly, assuming you can find your keys, but it is certainly not as quick as if you were already in the car with the engine running. The final category of reserves are called operating reserves. Operating reserves are generators that can be brought on line, but which require at least

30 minutes to do so. For example, as a private pilot, I can tell you that you don't simply jump into an airplane, start the engine and fly off as quickly as you can drive off in your car.

Figure 1 provides a chart showing how the four different types of reserves work together.

Figurel: The Four Types of Reserves



Gas-fired generators provide most reserve capacity because they can be started, stopped, or ramped up and down fairly easily. In contrast, coal and nuclear plants are designed to run around-the-clock, generating the same amount of power all the time. Starting up a nuclear plant, for example, takes several days, and a baseload coal plant can take many hours. Although the output of both types of generating plants can be adjusted, doing so increases the "wear-and-tear" on them and raises their operating costs.

Intermittent Resources Increase the Need for Reserves

Given this description of the four types of power system reserves, it is not surprising that intermittent resources like wind and solar PV cannot provide those reserves by their very nature. Because you cannot count on the wind blowing at a certain time on a certain day, a wind turbine cannot be relied on to provide electricity if suddenly called on. And, if you have a sudden need for backup generating capacity after dark, solar PV cannot help.

In fact, intermittent resources increase the need for reserves. The reason for this is that, not only must system operators ensure the reliability of the electric system by (1) addressing constantly changing demand, (2) having enough reserve capacity to meet demand when it is at its highest, and (3) planning for low-likelihood contingencies, they must also (4) cope with the wide swings in output from intermittent resources. That, in a nutshell, is what integrating intermittent generating resources is all about, and why integrating intermittent resources is both challenging and costly.

The integration challenge is exacerbated as the quantity of intermittent resources increases on the power system. For example, peak electric demand in PJM is over 100,000 MW in the summer. If PJM system operators had to integrate 10 MW of solar PV, doing so would be trivial. The amount of solar PV is so small that its impact on the overall PJM system would be negligible.

However, the integration challenge becomes and is far more difficult and more costly to address as the quantity of intermittent resources increases. Today, wind generation, with over 60,000 MW installed, is by far the largest intermittent resource and is clustered in the windier regions of the country, including the Pacific Northwest, Texas, and the Midwest. Texas, for example, has over 12,000 MW of wind generating capacity, California over 5,500 MW, and Iowa has over

5,000 MW. There is about 7,000 MW of wind in the Pacific Northwest that the Bonneville Power Administration must integrate. The Midwest ISO (MISO), which spans across 15 states, including most of Illinois, Indiana, Iowa, Michigan, Minnesota, and Wisconsin, integrates over 12,000 MW of wind capacity.

Some Examples

The magnitude and concentration of wind generation in these states has made integration more difficult and costly, and posed challenges for maintaining overall system reliability. The problem stems from huge swings in wind generation in very short periods of time. For example, on October 28, 2011, wind generation decreased in MISO by 2,700 MW in just two hours. In ERCOT, on December 30, 2011, wind generation decreased 2,079 MW in one hour and over 6,100 MW between 6AM and 4PM that day.[1] Still another example took place on October 16, 2012. On that day, wind generation on the Bonneville Power Administration system was 4,300 MW, accounting for 85% of total generation in the pre-dawn hours. The next day, wind generation fell almost to zero.

Not only do such large swings in generation by intermittent resources pose reliability concerns, so does the pattern of generation availability. Whereas solar PV tends to provide the greatest amount of generation on days when power demand peaks – such as those hot, sultry, and windless August days in DC – wind generation tends to be least available when demand is greatest, and vice-versa, as I have documented in my own published research.[2]

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1 *See* "In a first, wind exceeds hydro in BPA region," Platt's *Megawatt Daily*, October 19, 2012, p. 9.

2 Jonathan Lesser, "Wind Generation Patterns and the Economics of Wind Subsidies," *The Electricity Journal*, Vol. 26, No. 1, January/February 2013, pp. 8-16.

Chicago's experience during last summer's heat wave provides a compelling local example of wind power's failure to provide power on the hottest days. During this heat wave, Illinois wind generated less than 5% of its capacity during the record breaking heat, producing only an average of 120 MW of electricity from the over 2,700 MW installed. On July 6, 2012, when the demand for electricity in northern Illinois and Chicago hit a record of over 22,000 MW, the average amount of wind power available on that day was a virtually nonexistent 4 MW.[3]

Integration and Interconnection Costs

By definition, generating resources that are part of the "bulk power system" are those which are electrically connected to the power grid. A regional system like PJM or MISO, for example, has hundreds of generating plants, whose operations are all coordinated by system operators.

Historically, most generating plants were built near load centers. For example, generating plants were built near DC along the Potomac River to provide electricity to the city. Building generating plants near load centers reduces costs in two ways: first, it reduces the amount of power that is "lost" over transmission lines because of electrical resistance and, second, it reduces the need to build miles of transmission lines to deliver power to those load centers.

Today, new gas-fired generating plants are built near load centers. The plants have small footprints and are clean. In New York City, for example, new gas-fired generators have been built in Brooklyn and Queens, both to meet growing electric demand and to replace the generation from old, inefficient and highly polluting oil-fired plants.

[3] Jonathan Lesser, "Wind Power in the Windy City: Not There When Needed" *Energy Tribune* (op-ed) July 25, 2012.

Although solar PV can be installed on rooftops, wind generators are typically built in remote regions. There are several reasons for this. First, wind generators have to be built where the wind is, which tends to be more remote areas of the Midwest and western Texas. Second, wind generation requires a lot of land area because wind turbines cannot be sited too closely together. (Otherwise, they interfere with each other's air flow, and reduce generation.) Because land is generally expensive in populated areas, wind generation developers have thus located turbines on low-cost land far from load centers.

As a result of locating wind generation (and some solar facilities) in remote areas, billions of dollars must be invested in new transmission lines to deliver that power to cities and towns where the electricity is needed. Texas, for example, has built a series of transmission lines, called CRES, to connect wind generation in west Texas to the population centers in eastern Texas. Total cost so far: $6.9 billion.

III. THE COST OF INTEGRATING INTERMITTENT RESOURCES

As discussed in Section II, to ensure system reliability, operators must ensure there is enough reserve capacity to meet contingencies. As more intermittent resources are added to the power system, one of the most important contingencies has become the potential lack of supply from these resources. Again, given its magnitude, wind generation is far more of an issue than is solar PV. Second, the costs of building new transmission lines to connect intermittent resources to the power grid must be included.

The potential loss of thousands of MW of intermittent generation in a short time frame means that system operators must increase the quantity of available reserve capacity. This means the need for spinning, non-spinning, and operating reserves increases, which increases costs. It is as if thousands of vehicles are required to have their engines idling, waiting for the possibility they will be needed.

Furthermore, the variability of intermittent resource output increases the costs of load following. Not only must system operators compensate for constant changes in electric demand, they must also compensate for constant changes in intermittent resource output. As a result, more gas-fired generators must be sped up and slowed down to ensure supply and demand match. That's costly, more so than simply operating a generator at a constant rate for long periods of time. Operating gas-fired generators in this way is inefficient (like stop-and-go driving in the city), which increases costs and air pollution.

In regions with wholesale electric markets, such as Texas, the Midwest, and PJM, system operators use next-day forecasts of generator availability and demand to determine how they will ensure the power system can meet demand and operate safely. For these planning efforts, it is also crucial to forecast intermittent resource availability, because those forecasts determine the quantity of reserve generating capacity that system planners must ensure is available "just in case."

Although even wind advocates acknowledge wind's inherent intermittency, they claim wind generation can be predicted accurately several days in advance, allowing system operators to reduce, if not eliminate, the impacts of wind's volatility.[4] However, forecast and operational data in areas including Texas, as well as in European countries, do not support such forecast

[4] *See, e.g.*, M. Delucchi and M. Jacobson, "Providing All Global Energy with Wind, Water, and Solar Power, Part II: Reliability, System and Transmission Costs and Policies," *Energy Policy* 39 (2011), pp. 1170-1190.

accuracy claims.[5] In other words, forecasting intermittent resource availability is not especially accurate. This adds to the costs of integrating intermittent resources because inaccurate short-term forecasts of intermittent generation increases the overall cost of meeting electric demand: system planners either must reimburse other generators who had been scheduled to operate, but were not needed because actual wind generation was greater than forecast, or reimburse those generators because they had not been scheduled, but were required to operate because actual wind generation was less than forecast.

Integration Cost Estimates

There have been a number of studies of the costs of integrating wind generation. In 2011, the National Renewable Energy Laboratory (NREL) published its Eastern Wind Integration Study (EWITS), which focused on the integration costs associated with maintaining system reliability.[6] In December 2012, the American Tradition Institute (ATI) published a study that also estimated the additional costs associated with building transmission lines, power losses along those lines, and the additional fuel costs associated with operating fossil-fuel generation needed to "firm up" intermittent generation.

The studies show that reliability-related integration costs increase on a per megawatt-hour (MWh) basis as more wind generation is added. This makes intuitive sense: very small amounts of wind or solar PV will have little or no impact on overall system reliability. However, as more and more intermittent generating resources have been added, their adverse impacts on reliability

5 K. Forbes, M. Stampini, and E. Zampelli, "Are Policies to Encourage Wind Energy Predicated on a Misleading Statistic?" *The Electricity Journal* 25 (April 2012), pp. 42-54 (Forbes et al. 2012).

6 NREL (National Renewable Energy Laboratory), Eastern Wind Integration and Transmission Study, February 2011, NREL/SR-5500-47078. Available at: www.nrel.gov/wind/systemsintegration/ewits.html, www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

have increased. These impacts will only become more pronounced, and the integration costs incurred to maintain system reliability larger, as more intermittent resources are added to the power grid.

Based on the NREL study, which reported a range of reliability-related integration costs between $1 per MWh and $12 per MWh, a typical cost estimate for reliability-related integration costs of intermittent generation is $5 per MWh. In Texas, for example, applying this value to the 12,000 MW of installed capacity, and assuming a 30% capacity factor (where a generator running around-the-clock for an entire year would have a 100% capacity factor), this implies integration costs of over $150 million per year – costs that must be paid by electric consumers in Texas to ensure reliability.

The 2012 ATI study estimated the costs of the additional fuel consumption associated with having to cycle fossil generators to meet changing intermittent resource generation levels, as well as the additional costs associated with building new transmission lines and the power losses on those lines. In some cases, there may be sufficient existing transmission capacity to avoid the need to construct new lines. However, even if that is the case, there will still be line losses whose costs are part of integrating intermittent resources located far from load centers.

Using data from EWITS, they estimated the cost of new transmission lines built to deliver power generated by far-flung wind units to be $15/MWh. They also derived an estimate of $12/MWh as the cost of the line losses, for a total of $27/MWh. If we apply these values to Texas, where transmission was built specifically to deliver wind generation to load centers hundreds of miles away, the additional cost is over $850 million per year. Thus, the reliability-related and transmission/losses costs for Texas alone are $1 billion per year.

IV. SUBSIDIES AND COST SOCIALIZATION ARE EXACERBATING INTEGRATION COST ISSUES

The fact that integrating intermittent generating resources is more costly than schedulable resources is not the reason for this hearing. Instead, this hearing seeks to examine the reliability challenges of integrating these resources. The issue of maintaining the reliability of the power system in the face of the shifting energy landscape, as the hearing's title frames it, and the resulting integration costs can be traced directly to (1) subsidies designed to incent construction of intermittent resources; and (2) socialization of integration costs.

Consider the following analogy: long-haul trucks typically are assessed road taxes based on their weight. The reason is that, the heavier the truck, the greater the damage caused to roadways. Assessing road taxes based on the damages caused makes intuitive sense, both from the standpoint of economic efficiency and fairness. Thus, the fact that long-haul trucks cause more road damage than passenger cars is not an issue because truck owners pay those costs. There may be disagreements as to whether the taxes are set correctly, but the "user pays" principle is reasonable.

In the case of intermittent resources, however, the subsidies and mandates designed to incent their development, such as the wind production tax credit (PTC) and individual state renewable portfolio standards (RPS), plus the socialization of integration costs among all users, has increased reliability concerns. In other words, we have put into place policies that exacerbate inefficient investments because they do not require intermittent resource developers to pay the full costs of their investments. As Commissioner Donna Nelson of the Texas Public Utility Commission stated last year:

> Federal incentives for renewable energy ... have distorted the competitive wholesale market in ERCOT. Wind has been supported by a federal production tax credit that provides $22 per MWh [now $23 per MWh] of energy generated by a wind resource. With this substantial incentive, wind resources can actually bid negative prices into the market and still make a profit. We've seen a number of days with a negative clearing price in the west zone of ERCOT where most of the wind resources are installed ... The market distortions caused by renewable energy incentives are one of the primary causes I believe of our current resource adequacy issue ... [T]his distortion makes it difficult for other generation types to recover their cost and discourages investment in new generation.[7]

Subsidies Contribute to Premature Retirement of Schedulable Resources, Which Reduces System Reliability

Although not specifically limited to wind generation, approximately 75% of the total PTC credits claimed to date have been for wind generation.[8] The magnitude of the PTC subsidy—far larger than any other form of production based energy subsidy[9] has incented thousands of MW of wind generation.[10] Therefore, I will focus my testimony on its impacts on system reliability.

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7 Chairman Donna Nelson testimony before the Texas Senate Natural Resources Subcommittee (September 6, 2012), transcribed from http://www.senate.state.tx.us/avarchive/ (emphasis added).

8 M. Sherlock, CRS. "Impact of Tax Policies on the Commercial Application of Renewable Energy Technology," Statement Before the House Committee on Science, Space, and Technology, Subcommittee on Investigations and Oversight & Subcommittee on Energy and Environment, April 19, 2012, p. 3.

9 U.S. Energy Information Administration, "Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010," July 2011. www.eia.gov/analysis/requests/subsidy/.

10 For, example, the American Wind Energy Association states, "Equipped with the PTC, the wind industry has been able to lower the cost of wind power by more than 90%, provide power to the

Currently, the PTC is $23 per MWh. Because it is a tax-credit, on a before-tax basis, it is over $35 per MWh. That amount is actually higher than the market price of electricity in many regions, because of low natural gas prices. Basic economic principles state that you don't operate your plant if doing so costs more than the value of the output you produce. For example, an old, inefficient generating plant that consumes $50 worth of fuel to generate one MWh of power will not generate if the price of electricity is less than $50 per MWh.

With the PTC, however, the economics change. If that same generator received a $35 per MWh tax credit, then it makes economic sense to operate as long as the price of electricity is at least $15 MWh ($50 - $35 = $15). The cost of operating a wind generator is close to zero.

It turns out that electric market prices can actually be negative. Although that sounds impossible – why would anyone ever pay you to use their product? – it happens in the power industry. The reason is that baseload generators cannot just be switched on and off at will. Thus, these plants will continue to operate regardless of the price of electricity.

Now, if there were no PTC, then wind generators, which can be switched off at will, would not generate any power whenever prices were negative. However, with a $35 per MWh PTC, they will continue to generate as long as the price of electricity is greater than -$35 per MWh. Coupled with the fact that wind generation tends to produce the greatest amount of power at

equivalent of over 12 million American homes, and foster economic development in all 50 states." *See*, AWEA Fact Sheet, "Federal Production Tax Credit for Wind Energy." http://www.awea.org/issues/federal_policy/upload/PTC-Fact-Sheet.pdf .

night and in Spring and Fall, when electric demand is lowest, the wind PTC has greatly exacerbated the number of hours where electric prices are negative.[11]

Although negative prices may sound like a great deal, from a reliability standpoint, they are harmful. The reason is that the more hours of the year prices are negative, the greater the losses to fossil fuel generators who must run, and the greater the likelihood they will shut down because of uneconomic subsidies provided to intermittent generating resources. For example, last October, PPL corporation announced it was considering shutting down its Correte coal-fired plant in Montana because of subsidized wind generation, stating:

> "Wind farms can make a profit even in low demand time of the season . . . because they can pay people to take their electricity . . . What we want to see is a level playing field for our plants. What bothers us is that there are actually companies paying people to take their power"[12]

Last December, the company announced it was selling all of its Montana generating plants, including Corrette, because it cannot operate the generating units profitably. .[13]

As schedulable generating plants shut down because it is uneconomic for them to operate, they jeopardize reliability, and increase the costs of maintaining reliability because additional gas-

[11] *See* F. Huntowski, A. Patterson, and M. Schnitzer, "Negative Electricity Prices and the Production Tax Credit," The Northbridge Group, September 14, 2012. http://www.nbgroup.com/publications/Negative_Electricity_Prices_and_the_Production_Tax_Credit.pdf. *See also*, Testimony of Public Utilities Commission Chairman Donna Nelson, Before the Texas Senate Natural Resources Subcommittee (September 6, 2012), transcribed from http://www.senate.state.tx.us/avarchive/.

[12] T. Howard, "PPL Montana Officials Discuss Potential Shutdown of Corette Plant," *Billings Gazette* September 21, 2012.

[13] M. Dennison, "PPL Montana putting its Montana power plants up for sale, industry sources say," (Helena) *Independent Record*, December 23, 2012. http://helenair.com/news/local/ppl-montana-putting-its-montana-power-plants-up-for-sale/article_9e7f6c22-4ca5-11e2-8e7e-0019bb2963f4.html.

fired generators must be placed on stand-by or operated at a higher cost. Thus, rather than being able to schedule a "least-cost" mix of baseload (round-the-clock), intermediate, and peaking generators, those operators will have to meet electric demand with a more costly mix of resources, and spend more to ensure there are sufficient reserves to meet all contingencies.

Subsidies Incent Inefficient Development of Intermittent Generating Resources, Which Exacerbates Reliability Concerns and Raises Integration Costs

Subsidies promote development of generating resources that would not otherwise be competitive. And, on a per-MWh basis, intermittent generating resources receive the largest subsidies by far. At a pre-tax value of $35 per MWh, the PTC is often greater than the market price of electricity. For example, in 2012, the overall average price in the PJM electric energy market was $33.11 per MWh – less than the PTC![14] A subsidy that is greater than the average market price introduces huge market distortions.

Consider an analogy: suppose the government subsidized gasoline to such an extent that consumers paid a price of just one penny per gallon. The amount of driving and total gasoline use would skyrocket, increasing congestion, sprawl, damage to highways, and air and water pollution. The market for fuel efficient vehicles would quickly collapse.

The PTC, coupled with socializing almost all of the reliability-related integration costs caused by intermittent resources, is driving huge levels of investment in intermittent resources, especially wind generation, exacerbating reliability issues and raising integration costs still further. As more wind generation is developed, it is built in locations with less favorable wind conditions

[14] *See* PJM, 2012 State of the Market Report, p. 51. Available at: http://www.pjm.com/~/media/documents/reports/state-of-market/2012/2012-som-pjm-volume2-sec2.ashx

and thus lower overall economic efficiency. This is not unusual – it makes sense to develop the lowest cost resources first, because they provide the greatest return on investment. But when such a large percentage of development costs are socialized – the PTC is paid by taxpayers and integration costs (reliability-related and new transmission lines) are paid by all electric consumers – the result is inefficient investment that would not take place but for the subsidies.

There is justification for the socialization of some transmission-system costs, because transmission capacity provides for reliable electric service, which is a public good. Thus, to the extent that additional transmission capacity increases system reliability, a reasoned economic argument can be made that, because all users of the transmission system benefit from improved reliability, the costs should be shared among all users. In essence, this is a beneficiary-pays approach to cost allocation. However, subsidized (and unsubsidized) intermittent generation does not improve reliability. In fact, it reduces reliability because of its inherent unpredictability/variability, which requires additional back-up generation and raises integration costs.

Despite this adverse reliability impact, the costs of new high-voltage transmission capacity built to deliver intermittent resource-generated electricity onto the power system are still socialized among all users, who then incur yet more costs to maintain the reliability of the power system because it is adversely affected by the intermittent resources. The net effect is to increase the magnitude of the costs that are socialized because subsidies encourage excess intermittent resource development.

V. MYTHS AND FACTS

Many (but not all) proponents of intermittent resources employ a variety of justifications for their continued subsidization. These include: (1) that it is necessary to protect "infant" industries so they may become fully competitive in the market, (2) that geographic dispersion of intermittent resources smooth's out the ups-and-downs of their output (*i.e.*, if the sun is not shining or the wind is not blowing in location A, they will be in location B); (3) that intermittent resources will lead to energy "independence" from Middle East oil; (4) that price "suppression" caused by subsidized intermittent resources benefits consumers; and (5) that intermittent resources are helping the economy by creating new "green" industry and "green" jobs. None of these arguments has any basis in fact.

The "Infant Industry" Myth

The first proponent of the "infant industry" argument was none other than Alexander Hamilton, over two centuries ago, to justify tariffs that would protect U.S. industries from imported goods. However, the reality is that intermittent generation resources have been subsidized since enactment of the Public Utilities Regulatory Policy Act of 1978. Production and investment tax credits have been in place for over two decades, since the passage of the Energy Policy Act of 1992. And, 30 states plus the District of Columbia have RPS mandates and eight others have RPS goals. No other forms of generation have ever been provided with both production subsidies of their costs and mandates that they be used. After 35 years of subsidies, and 60,000 MW of installed capacity, it is difficult to argue the wind industry is in its "infancy." In fact, the U.S. Environmental Protection Agency considers wind a "mature industry." Moreover, unlike solar PV, the prospects for further reductions in wind generation costs are likely small.

It is certainly true that other generating resources have been subsidized. None, however, have been subsidized to the extent of intermittent generation, with direct production tax credits and usage mandates. The way to eliminate the adverse effects of subsidies – be they for energy, agriculture, or housing – is to eliminate subsidies. In an April op-ed in the *Wall Street Journal*, Patrick Jenevein, the CEO of wind generation developer Tang Energy, said the following:

> If our communities can't reasonably afford to purchase and rely on the wind power we sell, it is difficult to make the moral case for our businesses, let alone an economic one. Yet as long as these subsidies and tax credits exist, clean-energy executives will likely spend most of their time pursuing advanced legal and accounting methods rather than investing in studies, innovation, new transmission technology and turbine development.[15]

In other words, Mr. Jenevein stated an obvious, but unspoken truth: the presence of subsidies drives developers to devote their efforts to continuing those subsidies, rather than improving the efficiency of their product.

<u>The Geographic Dispersion Myth</u>

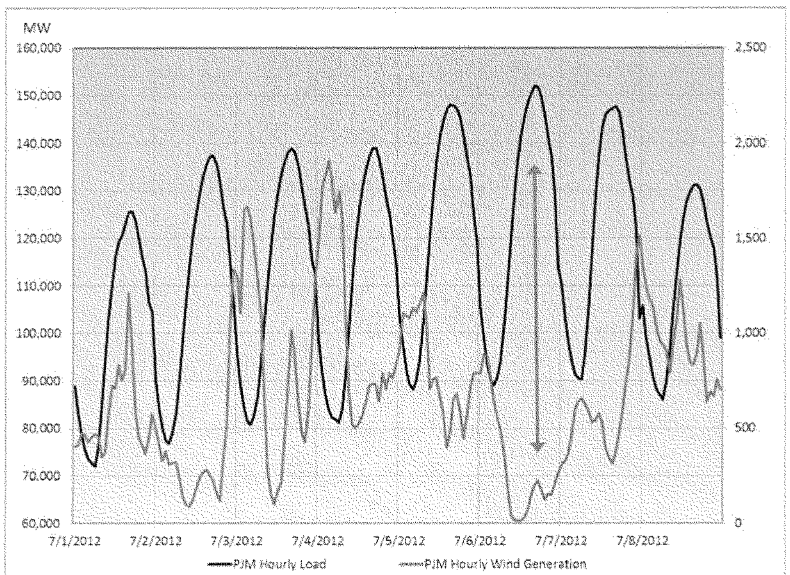
Yet another myth is that the broad geographic dispersion of intermittent resources reduces, or eliminates, the variations in output that exacerbate reliability problems. My detailed research[16] of wind generation over a four-year period in Texas, the Midwest, and PJM shows this to be false. Figure 1, for example, compares wind generation throughout all PJM – which extends

[15] P. Jenevein, "Wind subsidies: no thanks," *Wall Street Journal*, April 2, 2013. http://online.wsj.com/article/SB10001424127887323501004578386501479255158.html.

[16] *See* J. Lesser, note 2, *supra*.

from Michigan in the north, to Kentucky in the southwest, to Virginia in the southeast – and hourly loads during the week of July 1-8, 2012, when the eastern half of the country was suffering a heat wave.

Figure 1: PJM Hourly Load and Wind Generation, July 1-8, 2012



The figure clearly shows the huge volatility of wind generation from hour-to-hour. Worse, it shows an inverse relationship between wind generation and electricity demand: the greater the demand, the less the amount of wind, and vice-versa. From a reliability standpoint, this is the worst sort of generation pattern: when demand is at its highest, you want to have as much generation available as possible to meet that demand.

Moreover, this same pattern is repeated throughout the year. Geographic dispersion does not reduce the volatile ups-and-downs of intermittent resource output.

The Energy Independence Myth

Still another myth is that intermittent resource development will promote independence from Middle East oil. This argument is clearly false, because the amount of petroleum used to generate electricity is negligible. Thus, until electric vehicles replace the majority of internal-combustion vehicles on the road, the idea that intermittent generating resources will help secure energy independence is clearly false.

The Price Suppression Myth

Intermittent generation developers (and other developers who receive subsidies to development generating plants) point to the "benefits" of lowering or "suppressing" market prices. Although artificially reducing prices may sound like it benefits consumers – it imposes far greater long-run costs.

In a recent research paper,[17] Pennsylvania State University professors Briggs and Kleit examined this issue. Their work finds that the "benefits" of price "suppression" quickly disappear, as government intervention drives out otherwise economic existing generation and hinders the development of new resources in all states within the market. The reason is that subsidies, and

[17] R. Briggs and A. Kleit, "Resource Adequacy and the Impacts of Capacity Subsidies in Competitive Electricity Markets," Working Paper, Dept. of Energy and Mineral Engineering, Pennsylvania State University, October 22, 2012 (Briggs and Kleit). http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2165412

even the threat of future subsidies, drives legitimate competitors out of the market, reducing unsubsidized supplies. Investors become far more wary of providing capital for new development, leading to an increase in financing costs and, again, less investment in the market. While subsidies benefit intermittent resource developers, they harm competitive markets and, thus, raise prices for consumers: the few benefit at the expense of the many.

Thus, when government intervenes on behalf of one generator it drives out other generators, taking with it not only competitive generation capacity, but also the jobs and tax base associated with generation that exits the market. Most importantly, they find that the adverse long-run impacts in all states far outweigh any short-term "benefits" of temporary price reductions.

The Green Jobs Myth

Finally, there is the "green" jobs myth, that subsidizing green energy, including intermittent generation, will create economic growth. Basic economics shows that this, too, is another myth.[18]

You may have read about studies promoting the jobs potential of renewable generation and energy efficiency programs. Such programs, these studies conclude, will foster new industries and create thousands of new well-paying jobs. The more stringent the requirements and mandates, the greater the economic growth. The fatal flaw of these studies is they typically assume that the money to pay for these mandates falls from the sky. In reality, the money comes from all of us in the form of higher electric costs, higher taxes, or both. It is as if the sponsors of those studies conducted a cost-benefit analysis and completely ignored the cost side. Such an

18 *See* J. Lesser, "Renewable Energy and the Fallacy of 'Green' Jobs," *The Electricity Journal*, Vol. 23, No. 7 (August/September 2010), pp. 45-53.

analysis will always conclude the benefits are greater than the costs, because you have assumed there are no costs.

A number of European countries, including Denmark, Germany, and Spain have tried to do so with renewable energy mandates. As a result, Danish businesses and consumers pay the highest electric rates in the world. Germany and Spain have limited their renewable programs, because the programs have been so costly and the resulting job creation so limited. They, too, pay very high electric rates that have damaged their competitiveness.

The fact that higher electric costs reduce economic growth and jobs is really just basic economics. For example, in April 2010, the Rhode Island Public Utilities Commission (PUC) rejected a proposed power purchase contract between Deepwater Wind (a small offshore wind development) and National Grid. One of the reasons cited by the Rhode Island PUC was the job-killing effects of higher electric prices:

> It is basic economics to know that the more money a business spends on energy, whether it is renewable or fossil based, the less Rhode Island businesses can spend or invest, and the more likely existing jobs will be lost to pay for these higher costs.[19]

The Rhode Island PUC was not rejecting wind generation per se; it was rejecting a specific project that was far more expensive than other wind generation alternatives, and more expensive than the market price of power.

[19] *In Re: Review of New Shoreham Project Pursuant to R.I. Gen Laws § 39-26.1-7*, Docket No. 4111, Report and Order, April 2, 2010, p. 82. Subsequent to rejecting the proposed contract, the Rhode Island legislature passed a law that, in essence, mandated the Rhode Island PUC to approve the contract.

Subsidizing intermittent generation leads to higher long-run electric prices, reduced reliability, and greater integration costs to restore reliability. Higher electric prices reduce job growth. Despite the temptation, you simply cannot subsidize your way to long-term economic growth. That is the ultimate "free lunch" assumption, and it is simply untrue.

VI. CONCLUSIONS AND RECOMMENDATIONS

As the Committee addresses these issues, I offer the following conclusions and policy recommendations:

1. To the extent possible, require all generators to pay for the reliability-related integration costs they cause, rather than socializing those cost across all electric consumers. Because intermittent generation has higher per MWh, integration costs than schedulable resources, requiring those generators to bear the costs they cause makes greater economic sense than further subsidizing them.

2. Eliminate all subsidies paid to electric generators, whether they are intermittent resources or schedulable resources. The subsidies provided by the PTC and state RPS mandates are especially distorting to markets, because of their magnitude and because they are production based, e.g., generators receiving this credit are incented to generate power even when power is not needed. Subsidizing intermittent generation is exacerbating reliability problems, causing increases in integration costs, and jeopardizing the stability of competitive electric markets. The wind PTC is especially egregious, because in many cases it is larger than the actual market price of electricity. Continuing subsidies for intermittent resources will lead to higher electric prices and reduced system reliability.

Thank you for the opportunity to testify before the Committee today.

Mr. WHITFIELD. Thank you very much, Dr. Lesser.

And thank all of you for your testimony.

At this time, we will begin the questions, and I will recognize myself for 5 minutes of questions.

In your testimony, Dr. Lesser, you had a paragraph or so, and basically in which you said that increasing use of intermittent generating resources does create obstacles to reliability or at least it exacerbates reliability, and it increases integration cost to the consumers. Would you elaborate on that a little bit for me?

Mr. LESSER. Sure. The problem with integrating intermittent resources, like wind and solar, is that you have to, in addition to planning for the ups and downs of demand all the time, you have to have additional reserve capacity in case the wind stops blowing suddenly, and that has happened. Well, that means you have to have additional costs incurred for other reserve capacity. As a result, that increases cost.

Because wind is subsidized, you get more of it, you get greater investment in wind power. That is why you have a subsidy. That tends to increase the amount of wind capacity that exacerbates the reliability issues that grid operators have to deal with. Plus when you socialize transmission costs, such as building new transmission lines in Texas, which is now up to a cost of over $7 billion, that again, you are incenting that sort of investment, which raises costs for everyone and creates more reliability problems.

It is true that, you know, the grid operators can handle wind reliability at this point. I mean, the lights are on in here, that is true, but as you increase, though, that, the amount of wind penetration on the system, those costs will keep increasing, and it will become more difficult to maintain a reliable power system.

Mr. WHITFIELD. Now, you know, the production tax credit was recently extended for the wind industry, and we hear a lot about negative pricing or selling electricity generation at less than your cost. There is quite a bit of that going on in the wind industry. Would you elaborate on that?

Mr. LESSER. Yes, Mr. Chairman. Negative pricing sounds great. It actually happens—and it sounds very strange because why would anyone, why would the market price for any good ever be negative? You know, why would someone want to pay you to buy what they are selling?

But because of the production tax credit is negative 23—is $23 per megawatt, that translates on a before tax basis of $35 per megawatt. Well, so wind power producers get in at production tax credit, have an incentive to bid in their generation into the market as long as the price is greater than negative $35. And because other power producers, like nuclear and coal plants, which are designed to run round the clock, they keep their system operating. They can't just shut the plants down. So you end up with excess supply in certain times of the year and you end up with negative prices. That the hours of negative pricing during the year is actually increasing.

What you have now is when those prices are negative, so those coal nuclear operators are actually having to pay the grid to keep operating. That obviously increases their cost, reduces their profitability; they are having to shut down.

In Minnesota, for example, I believe they announced the closure of one coal plant because of subsidized wind. Therefore, what happens is, you start shutting down those plants that are needed for reliability because of wind, subsidized wind generation, well, you still have to maintain reliability, so you have to have more reserve capacity, which again, increases cost.

Mr. WHITFIELD. All of us, I think, recognize that the Clean Air Act has been a good piece of legislation, and as the gentleman from California said, our CO_2 emissions are the lowest they have been in 20 years.

Are any of you familiar with EPA providing an exemption to a fuel source for the purposes of being a backup, as you mentioned in your demand response paragraph, Mr. Shelk, where EPA has now exempted diesel fuel engines from the Clean Air Act?

Mr. SHELK. That is correct, Mr. Chairman.

In a rule, a final rule in January called RICE NESHAPS, which it stands for Reciprocal Internal Combustion Engines, and this is the important part, this is for the Hazardous Air Pollutant Standards, and this is an interesting issue because it unites in the litigation pending in the D.C. Circuit and before EPA power generators, power health groups, environmental organizations, states, everyone but the demand response community oppose this, and EPA decided that these backup engines should be exempt, these diesel engines.

Now, to their credit, they did require ultralow sulfur diesel, but the problem is we went to EPA and said, look, you have to understand how this rule overlays with electric power markets. And this is sort of the classic case in government that we have all encountered of sort of stovepipe thinking where, when FERC acted to pay demand response, as I indicated, in 2011, we raised these environmental concerns about the backup generators. We said they should be excluded because the owner of the engine is not actually reducing demand. It is just taking less power from the grid, but they are turning on those uncontrolled diesel generators at the industrial facility, and FERC said, go talk to EPA. We raised this concern at EPA, and in the final rule, you will see EPA said, well, certain parties, meaning us and many others, raised this and you should go back to FERC.

So, it is sort of the two agencies really are talking to each other, and we are very concerned about this for the reasons that I have outlined and you mentioned, and again, this unites all of us, whether you are for coal or nuclear, natural gas, renewables; what is happening now is these small power plants, these backup diesel generators, can be linked together in the market. They can bid into the capacity market and the energy market where we get our revenue, regardless of what fuel source you prefer, and they are backing out those cleaner forms of generation, and we are hopeful EPA will reconsider the rule or the court will intervene.

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

I recognize Mr. Rush for 5 minutes.

Mr. RUSH. Again, thank you, Mr. Chairman.

Mr. Gramlich, you seem to be sitting there wanting to respond to some of the statements of Dr. Lesser. Do you have any response regarding the performance of the wind industry in my windy city of Chicago?

Mr. GRAMLICH. Yes. Thank you.

I mean, I didn't hear anything from Dr. Lesser that contradicted the statements I made about many parts of the country being able to reliably integrate vastly greater amounts of wind energy than we already have on the system.

We were just in our annual conference in Chicago with about 10,000 people, and Governor Branstad from Iowa came there and spoke, and he was raving about the 20 percent of their electricity that comes from wind. And I just saw also this week he announced that they are bringing 1,000 more megawatts. And I don't think he or MidAmerican Energy want an unreliable power grid; in fact, I think they want to further diversify their electricity portfolio.

When we were all here last and I testified before this same subcommittee, we were talking about the value of a diverse portfolio. And I am not saying we should do 100 percent wind on the grid, I am saying, as we all said then, every panelist said, yes, we need a more diverse portfolio. Wind would be just one part, but an important part, of that diverse portfolio. It will keep the lights on. And the costs, I don't disagree that there can be some incremental costs with integrating any resource, but you have to say, as compared to what? If you increase more wind on the grid, you may have, as I indicated, a very modest cost. If you put more large conventional plants on the grid, you also have an incremental cost.

Mr. RUSH. Thank you so much.

Mr. Sypolt, in your written testimony you mentioned that there are concerns in the Midwest Independent System Operator, MISO, region regarding the number of coal-fire-powered generators that would need to be retired and replaced with natural gas generators. You cited the testimony of MISO's executive vice president, Clair Moeller, from her March 19th, 2013, testimony before the subcommittee that MISO estimated that about 11.5 gigawatts of coal-fired generation may need to be replaced to comply with the environmental regulations, and that MISO was currently identifying potential impediments to integrating that amount of gas-fired generation in order to plan accordingly.

Are you aware of what some of those barriers might be? Do you have any concerns regarding the natural gas pipeline industry's ability to build the capacity or infrastructure that is needed in order to keep pace with the market demand in the MISO region or any other region?

Mr. SYPOLT. Thank you for the question, Congressman. And, you know, as I said earlier, the concerns that INGAA has are regionally targeted. MISO is one where a study had been done that said there are conversions that are going to occur from coal to most likely natural gas. Is there adequate pipeline capacity available?

INGAA is very confident that the pipeline industry is up to being able to build that pipeline capacity needed to meet the additional demand on the pipelines there. What is required, though, is that generators actually sign up for some firm transportation to make sure that capacity is built. I am not saying that every generating plant built has to have firm transportation, but I am saying there needs to be a review, which MISO actually did, that said, you know, there are situations where there may not be adequate pipeline capacity, and the only way that pipeline capacity would be built is if there are some long-term contracts signed that allows those pipeline builds to be economically built.

Mr. RUSH. Mr. Cicio, do you have any responses?

Mr. CICIO. I think that the—I would agree that we have a very good regulatory approach in how pipelines are built.

What we are concerned about, as I previously expressed, is that there is no entity that is overseeing this "pipeline capacity at peak demand concern." There is in the electric side of the market, there is the North American Electric Reliability Corporation that is evaluating the Nation for electric reliability. We are raising the question for a conversation that, you know, there is this absence of oversight in determining whether or not there is capacity problems in the natural gas pipeline, and so that is a concern.

Mr. WHITFIELD. At this time——

Mr. RUSH. Yield back.

Mr. WHITFIELD. At this time I recognize the gentleman from Texas Mr. Hall for 5 minutes.

Mr. HALL. I thank you, Mr. Chairman.

And, Dr. Lesser, I notice in your testimony you mentioned the myth of green jobs, and I sure agree with you that there is a lot of myth involved there. And I guess the question is whether or not subsidies for renewables really are creating sustainable job and economic growth.

The meeting today is about examining the challenges and the consumer impacts resulting from the increased use of natural gas and renewables. And I think sometime I would like to see us have a hearing here on really what fossil fuels do for us. And 2013 is not completed yet, but in 2012 indicates that from coal we get 37 percent of the preliminary U.S. electric generation and about 30 percent from natural gas. Those are hard, cold facts that we can't fight.

And Mr. Waxman is a wonderful member of this committee, and I have sat here with him for 30-something years. He continues to warn us, and in closing, about the threat of global warming will always be with us. And of course it will as long as he keeps putting in the Congressional Record and they keep talking about it. But without fossil fuels, we would all have to work our way or feel our way out of this building right today, and go to a car that wouldn't start, and get to a home that would be cold in the winter and too hot in the summertime. So we ought to have a hearing sometime on what fossil fuels are really still doing for us, but that is not what we are here for today.

We need fossil fuels, and we need to depend on it, and certainly I would ask you that. There is a lot of discussion on renewables. And do you see this as a realistic expectation? If not, why not?

Dr. Lesser.

Mr. LESSER. Well, thank you, Representative Hall.

Mr. HALL. Now, you almost answered in your—you almost answered it for me a moment ago, but go ahead and expand on that a little for us.

Mr. LESSER. Thank you, sir.

In my own view, you will see lots of studies that will show that, say, building more wind capacity, renewable generation subsidies will increase economic growth. Well, that is true, they will increase economic growth as long as the subsidies are continued, which is why they want to continue subsidies. The problem is those studies never look at the other side of the ledger, which is who is paying for it? They assume that the money just falls from the sky.

You simply cannot subsidize your way to long-term, sustained economic growth. That is economic free-lunchism. It does not work. It would be nice if it worked. We would all be a lot happier. We would have a much better economy in the country.

Europe has found this out. In Spain, Germany, Denmark, they are cutting back on their subsidies of renewable power because it simply doesn't work. They cannot afford it.

In terms of the sort of—I think you mentioned some of the global climate change and emissions, there is a small impact on emissions because of renewables, but it is very small, because you have to operate the remaining parts of the power grid more inefficiently by cycling conventional plants up and down. It is like the difference between driving your car in the city, where you are in stop-and-go driving, versus driving at a constant speed on the highway. It is less efficient; therefore, there are more emissions.

So the real—to the extent climate change is a significant issue, and you want to reduce carbon emission, then the question is what is the most efficient, what is the cheapest way of reducing those emissions? And I would suggest to you that subsidizing renewables is not the way. It is by far a very expensive way of reducing climate emissions, and there are much cheaper ways to do so.

Mr. HALL. And should Congress, then, permit recipients of subsidies, like the PTC, to bid negative prices in power markets?

Mr. LESSER. No, sir. In my view, all subsidies should be removed, not only subsidies for renewable resources, but also subsidies for conventional resources. You should have a level playing field in which all resources can compete.

It is funny, though, in this week's AWEA meetings that Mr. Gramlich referenced, AWEA is now advocating what are called master limited partnerships for wind developers. So not only will they get the PTC and a tax credit worth $35 per megawatt hour on a pretax basis, but you would have a corporate structure that doesn't pay income taxes. That is a really good deal. You get a tax credit, and you don't have to pay income taxes. I would like to have that for my business.

Mr. WHITFIELD. The gentleman's time has expired.

Mr. HALL. And I thank the chair.

Mr. WHITFIELD. At this time I recognize the gentleman from California Mr. Waxman for 5 minutes.

Mr. WAXMAN. Thank you, Mr. Chairman.

I assume, Dr. Lesser, those same mechanisms are available to fossil fuel enterprises, aren't they?

Mr. LESSER. No, they are not, sir.

Mr. WAXMAN. They are not.

Mr. LESSER. For gas pipelines, you have——

Mr. WAXMAN. Well, I think you are wrong.

Mr. LESSER. You would——

Mr. WAXMAN. I think you are wrong, and we could look at it very carefully. The REIT and the other tax reductions for fossil fuels are available.

Over the past 4 years, we have doubled our capacity to generate renewable electricity from wind and solar resources. Five percent of our electricity now comes from renewable sources other than hydropower. State and Federal renewable energy policies are playing an important role in driving this transition. The cost of renewable energy is also rapidly declining, and, therefore, wind power is already cost-competitive with fossil-fuel generation in some parts of the country.

We have made progress, but we need to do much more to reduce our carbon pollution and move towards a clean-energy economy. Low-carbon, low-cost renewable electricity should appeal to all members of this subcommittee, but instead of embracing this technology, some are attacking it.

Mr. Gramlich, we have heard testimony today that wind costs too much and impairs the reliability of the electric grid, so I am going to ask you some questions about these claims.

Does wind generation require large amounts of expensive backup fossil generation, and how much does the necessary backup power cost consumers?

Mr. GRAMLICH. Thank you.

No, it does not require large amounts of backup generation. All electricity sources rely on system backup from all other resources. And the costs of the wind reserves that are needed are about 6 cents out of a typical household's $140 monthly electric bill as compared to those costs for other conventional resources that are much higher.

Mr. WAXMAN. How do the costs of backup generation for wind compare to the costs of backup generation for conventional power plants?

Mr. GRAMLICH. The costs for conventional power is, at least in one study cited in my testimony, about 40 times higher, about $2.50 per monthly bill compared to the 6 cents that I stated a minute ago.

Mr. WAXMAN. The backup generation for wind is much cheaper, because variations in wind are slow and predictable, while a nuclear fossil-fired power plant can go offline instantly; is that correct?

Mr. GRAMLICH. That is correct.

Mr. WAXMAN. We have heard claims that wind is unpredictable and can suddenly stop blowing, adversely affecting electric reliability. Is that accurate?

Mr. GRAMLICH. No. Wind energy can be forecasted now with sufficient accuracy so grid operators can operate reliably and handle the fluctuations in a very low-cost manner.

Mr. WAXMAN. Mr. Weiss?

Mr. WEISS. Yes, Mr. Waxman. The North American Reliability Corporation looked at some of the kinds of claims that Dr. Lesser made and found them wanting. In their State of Reliability report of 2013, and I am going to read from the report, and I quote, "There were no significant reliability challenges reported in the 2012 summer periods resulting from the integration of variable generation resources."

Mr. WAXMAN. Thank you. I want to put that whole statement in the record.

Mr. WEISS. OK. Thank you.

Mr. WAXMAN. Let me ask about the production tax credit. Some argue that the cost of wind is so low, that the tax credit allows wind to bid negative prices into the market, and they say that these negative bids are undermining the profitability of other generation sources.

How often does this negative pricing occur, Mr. Gramlich, and how often is it affecting the market price for electricity?

Mr. GRAMLICH. It is extremely rare; far less than 1 percent of the time. Moreover, the occurrences have dropped by 60 percent in Texas, which is the area where this has been alleged, and they will be virtually gone as soon as transmission lines are put in place into these few localized areas in the country.

Moreover, it doesn't harm consumers. Low prices are a good thing. And the market price that is actually received by—if some were concerned with, say, fossil and nuclear plants, they are actually not receiving, those plants. It is almost never actually received by them.

Mr. WAXMAN. What about the price for consumers? Does wind generation increase utility bills or save consumers money? I gather your last statement was that it saves consumers money.

Mr. GRAMLICH. Right. It is saving consumers money.

Mr. WAXMAN. That is a good thing unless you want consumers to pay more money so they can continue to use coal even when natural gas would be cheaper, and even when wind may be cheaper.

Mr. Weiss or Mr. Gramlich, do you understand whether the REITs mechanisms and other tax mechanisms are available to fossil fuel industries, as they may well become available for renewable energy?

Mr. WEISS. As I understand it, Mr. Waxman, the master limited partnership is available and being employed now by oil companies.

Mr. WAXMAN. So it is a good way to raise money?

Mr. WEISS. Yes, it is.

Mr. WAXMAN. And raising money for enterprise, as I understand it, is supposed to be a good thing, investment by entrepreneurs to advance good business.

Mr. WEISS. And overall the Nuclear Energy Institute looked at subsidies overall over the last 60 years and found 70 percent go to fossil fuels, 10 percent have gone to renewables.

Mr. WHITFIELD. The gentleman's time has expired. And without objection, the document that Mr. Weiss referred to will be entered into the record.

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

Mr. WHITFIELD. At this time I will recognize the gentleman from Kansas Mr. Pompeo for 5 minutes.

Mr. POMPEO. Great. Thank you, Mr. Chairman.

You know, Ranking Member Waxman this morning said that some on our side are confused. He wasn't sure whether we liked cheap natural gas or not. Not confused. I like cheap natural gas, like cheap coal. Frankly, I like cheap energy. I like consumers to have affordable energy. There should be no confusion about that.

Mr. Sypolt, I want to talk to you about pipelines. Today I actually introduced a piece of legislation that will for the first time tell FERC, you have a deadline; you got to get your homework in on time. It will give every agency that has got a role in approving pipeline permits the chance to do their work and to decide whether or they like it or not. There is no requirement that they approve the pipeline, but it says you can't sit on it. You can't hang onto it forever. Gives them 12 months. There is an opportunity for an extension. We have got bipartisan support for that. It is being introduced by a lot of members of this committee: Mr. Matheson, Mr. Olson, Mr. Gardner, Mr. Johnson.

You know, we saw $30 gas at the Boston citygates in the Northeast not too long ago, and I just wanted to get your view of whether creating certainty for folks who are investing in pipelines and want to build these out will help our electric grid reliability.

Mr. SYPOLT. Thank you for the question, Mr. Congressman. And INGAA certainly supports your bill. We believe that anything that provides certainty and actually moves the process along more quickly so the pipelines can be built in the areas where they are needed can actually help reduce the cost of energy getting delivered into those areas.

I think FERC does a very good job today with their process, but they don't have all the authority they actually need to cause all the permits to be issued in a timely fashion. And the deadline that you proposed by your bill, we think, would be very helpful in assuring that pipelines are built in a timely fashion.

Mr. POMPEO. Mr. Shelk, in your written testimony, you talked about, so we have got this shale gas revolution, it is exciting. If the Federal Government doesn't mess it up, it will be very important to American manufacturing. It will be great for grid reliability as well. But you talked about being overconfident about anything in terms of the future. It wasn't that long ago that we thought we were out of natural gas as well.

Give me a sense of what you think the grid reliability implications are for that risk and how we as Federal policymakers ought to respond to the things that we might well not foresee.

Mr. SHELK. Thanks for the question.

I followed the hearing earlier this week and also an interview just this week from the former chair of the subcommittee, Phil Sharp from Indiana, who is now the president of Resources for the Future. And it was a long time ago, I think you go back to when I was here in the 1980s and 1990s, assumptions were made then, for example, that we were going to have to have a surcharge on every consumer to bring a very expensive pipeline down from Alaska. We had the Synthetic Fuels Corporation. I mean, you can kind of—the list goes on.

I think it was reassuring to hear the bipartisan testimony Tuesday that we are going to have game changers, that we couldn't predict then. But I think this committee, for example—we wouldn't have the natural gas revolution, the shale gas phenomenon, as I said in my written statement, unless this committee, again, coming together in the late 1980s saying, you know what, we made a mistake in the 1970s by thinking we could micromanage this with command-and-control regulation. And everybody on the committee, after some contention, to be sure, came together and removed the wellhead price controls, restructured the pipeline industry, removed the Fuel Use Act that said no natural gas could be used in power generation.

So my advice would be I think you set up the right mechanism. At FERC they are very vigilant about this. I would respectfully disagree with Mr. Cicio. There may not be something called the natural gas reliability entity, but you all in this committee created electric reliability organization in the form of NERC. NERC is looking at this. DOE is looking at this.

The bottom line is I think what we have seen is we can't predict what is going to happen, and therefore, the most flexible, adaptable system you can have is what works best. And I think market forces ultimately, within the confines of smart regulation, are good. What doesn't work is trying to micromanage today and say what the fuel mix should be and what percentages tomorrow.

Mr. POMPEO. So things like State RPSs which say "thou shalt" would be bad policy for any energy source?

Mr. SHELK. Well, now you are going to get me in trouble. Mr. Hall is not here, but Mr. Hall famously said when I was here decades ago that my friends are for the bill, and my friends were against the bill, and I am going to vote with my friends.

Mr. POMPEO. But, I mean, I think if you are——

Mr. SHELK. And in my business, if I have members behind me that are on one side and members on the other, I am going to support my members.

But to be serious, what we focus on, I think this is important, what Mr. Waxman was saying, under the Federal Power Act that this committee adopted in 1935, these are state-level decisions. And we may or may not agree with them, but what we focus on and what our members focus on is if a state wants to go down that road, number one, use competitive procurement so everybody competes to serve the business at the least cost to consumers. Number two, you have to have market rules to compensate the gas plants adequately, which is not happening today. States are behind. As the RPS standards, whether you like them or not, increase, as they will in the next 5 to 10 years, the states aren't adequately paying for the backup generation that exists.

Mr. POMPEO. Yes.

Mr. SHELK. So that is what we focus on. And you have got to get the market rules to match up with the RPS standards, and that often doesn't happen.

Mr. POMPEO. I appreciate that.

My time is up, but there are national implications to the State rules as well.

Mr. SHELK. Yep.

Mr. POMPEO. It affects the national grid and imposes costs on States that are not the State that put the law in place.

Thanks, Mr. Chairman.

Mr. WHITFIELD. At this time I recognize the gentleman from Texas Mr. Green for 5 minutes.

Mr. GREEN. Thank you, Mr. Chairman.

I thank our panel for being here.

The disconnect between incentives created by wholesale power market rules and the need for commitments that ensure the availability of pipeline capacity has been widely noted. What can Congress do to help this problem?

Now, I admit one of the worst decisions Congress ever made was back in the 1970s saying we can't use natural gas. Of course, back then natural gas was a very precious resource, and even 8 years ago it was $12, $13 in MCF. But Congress does overreact like they did in the 1970s. What can we do to help that certainty?

Mr. SHELK. A couple of thoughts there. One is, as the INGAA witness mentioned, and we would agree, there are wholesale market rules that need to be addressed. Where we disagree is you can't simply surgically say, well, if a gas-fired generator enters into a 20-year contract for firm gas transportation, we are just going to pass that along to consumers, because that could be a considerable expense.

So what happens is under the watch of FERC, the regions work on this, and they are doing that now. They are looking at those issues. So I think by holding the hearings you held last month, by continuing to hold hearings and do oversight of FERC that oversees the wholesale market, that is, I think, what Congress can do. There is really no need for additional legislation.

But what also needs to happen, and maybe there is a congressional role here, I am not sure, is it is not just the wholesale market, it is the retail market. And the retail market is under the jurisdiction of the states. And I will give you a specific example.

If we were to have gas-fired generators in New England enter into long-term contracts for gas transportation, one, it is not necessary most of the time. But put that aside, there are states in the region, Connecticut in particular, that has a bill moving through the legislature very rapidly as we are meeting today that would hot-wire a pipeline and a long-term contract for Canadian hydro from Quebec from a crown corporation in Canada that is opposed by the Governor of New Hampshire, it is opposed by Massachusetts, but if it is passed by Connecticut, it will artificially suppress the market price and make it very difficult for anybody to arrange for long-term gas transportation. So I think Congress can maybe help shed some light on that, but ultimately it is the jurisdiction over FERC.

Mr. GREEN. Well, I have to admit all my life I have heard about the Austin-to-Boston connection for natural gas, and I have always wondered why they still burned coal oil.

But anyway, Mr. Sypolt, my next question is I want to talk about the reliability of the natural gas pipelines. Do you or Dominion have many outages in what is key to the reliability in the pipeline sector, and what is the fundamental changes in your market area that is causing you to change your pipeline operations?

Mr. SYPOLT. Thank you for the question, Mr. Congressman. I would tell you that the pipeline, natural gas interstate pipeline, grid has been extremely reliable to serve those customers who have signed up for primary firm transportation. The pipeline system was designed around those contracts, and as there is growth in given markets, and there is the market signal from the market by way of a long-term contract that says they need additional capacity, that capacity is built, and those markets are served extremely reliably.

You asked about Dominion's experience with reliability. You know, we did go back and look at this for our primary firm contracts over a period of time, and our reliability has been absolutely phenomenal. We went back the last 3 years and had zero interruptions with regard to primary firm transportation. And I know there was one run we went 7 years where we had no impact on any primary firm contract. So the pipeline grid is extremely reliable for those who pay for that service.

Many times there are folks who refer to reliability as—a pipeline as not being reliable are really looking at interruptible-type transportation contracts, and you can't talk about that as reliability. The pipeline system was not designed to meet those on a reliable basis. That is actually transportation capacity issues by markets that are paying for it that are not using it at any given time, and when those markets who are paying for that under primary firm actually need it, that is when it is pulled back.

And that has really been much of the concern that INGAA has really talked about as you go forward, and more and more transportation is needed by growing markets. Whether that is power generation or industrial load or growing liquid distribution load, what it really says is there is going to be more and more demand on the pipeline system, and really counting on capacity that is not used by the current market that pays for that under primary firm is the real risk.

Mr. GREEN. Thank you, Mr. Chairman. I know I am almost out of time, but I have a couple of other questions on cogen, and I would like to submit it to the panel.

We went through that battle in the legislature in the 1980s, and at that time my friends were on both sides, and I was with my friends. But it worked out in Texas somehow that—and cogen—during cap and trade, I wanted cogeneration to be considered one of our energy savings, because it is such a benefit not only to the customers, but the industry.

But again, thank you, Mr. Chairman, for the hearing.

Mr. WHITFIELD. The gentleman's time has expired.

At this time I recognize the gentleman from Virginia Mr. Griffith for 5 minutes.

Mr. GRIFFITH. Thank you, Mr. Chairman. I appreciate it very much that you are having this hearing.

And also appreciate my friends from Dominion being here today. I know, Mr. Sypolt, that you are the gas guy, but do appreciate the fact that Dominion Energy has not abandoned coal, particularly central Appalachian coal, and was there at the ribbon cutting at the cleanest coal-burning plant that was opened up officially last September, and very proud of that facility. Unfortunately, of course, under new EPA regulations that have been proposed, that facility wouldn't be allowed to be constructed today, but we are awfully proud to have you all there in the Ninth District of Virginia creating jobs and bolstering our economy.

Does it make you nervous, though, and have to ask, when you think back on quotes from the President that indicate that he might not be so hot on natural gas? Of course, it seems that a lot of folks who were not for natural gas a few years ago are now for it because it seems to be the answer to a lot of problems. But I would have to think it would make you nervous, and I want to ask you that, when you remember that quote from the President in January of 2008 when he said, quote, When I was asked earlier about the issue of coal, you know, under my plan of a cap-and-trade system, electricity rates would necessarily skyrocket, even regardless of what I say about whether coal is good or bad, because I am capping greenhouse gases. Coal power plants, you know, natural gas, you name it, whatever the plants were, whatever the industry was, uh, they would have to retrofit their operations. That will cost money. They will pass that money on to the consumers.

Does that statement still make you nervous?

Mr. SYPOLT. Well, what I would say is, you know, Dominion certainly supports all forms of energy. And coal—you know, we have nuclear, we have coal, we have natural gas-driven power plants, we have wind generation, as well as building some solar and looking at some offshore wind as well, and have some hydro. So we certainly support all forms of energy, and we think our country needs all forms of energy.

Mr. GRIFFITH. And your company has always been diversified, and that has always been one of your market success stories is that you haven't put all your eggs in one basket. Nor should the United States of America put all of its eggs into one basket at any time, and we probably shouldn't eliminate that great black egg of coal from the basket of energy sources for the United States.

Let me move on to another question, if I might. Mr. Cicio, I would have to say to you, we have heard a lot of testimony about natural gas being cheap, but we heard testimony earlier this year that when natural gas hits that $4 mark, that coal once again becomes very, very competitive. And, of course, when you are trying to have that system that is secure, you want to have a diversity. And isn't it true that natural gas is expected to hit $4 by the end of the year? And I think in March it was already at $3.81, so that coal is once again very competitive if you are just looking at costs? And what we are really facing here are regulations that are hurting coal, not marketplace competitiveness.

Mr. CICIO. Well, that is right. It is critically important that coal—it is critically important for industrial competitiveness where small amounts of changes in the price of electricity makes a great deal. Coal needs to be in the mix. And $4 of gas bumps into very competitive coal prices.

Mr. GRIFFITH. And we are just about there, and probably——

Mr. CICIO. Yes.

Mr. GRIFFITH [continuing]. We will be in that neighborhood for some time.

Mr. CICIO. Yes.

Mr. GRIFFITH. Thank you very much.

Dr. Lesser, am I to understand that your concerns are that in other places in the world where they have relied on intermittent sources, and we heard that Germany was doing a good job of moving in that direction, but isn't it, in fact, the case that Germany is having some significant problems with their intermittent sources, and that it is actually affecting industry there because they can't count on the reliability?

And I am looking at an article from the Institute for Energy Research of January this year where they say, To illustrate the problem that renewable energy instability can cause, here is an example: electric grid weakened for just a millisecond at 3 a.m. The machines at Hydro Aluminum in Hamburg ground to a halt. Production stopped, and the aluminum belts snagged, hitting machines and destroying a piece of the mill with damages amounting to $12,300 to equipment. The voltage weakened two more times in the next 3 weeks, causing the company to purchase its own emergency system using batteries costing $185,000.

Are those the kind of stories that cause you concern? Do you have similar stories that you have heard?

Mr. LESSER. Those are certainly part of the issues that are of concern. For me, I think other issues are the, say—and especially in Europe, the cost of electricity is extremely high, which reduces economic growth. That is why they are cutting back on all their subsidies.

So my concern is here we are going down that same path, that we are making it much more difficult to maintain reliability. I know that ERCOT, the grid operator in Texas, is quite concerned about potential rolling blackouts this summer because of very high demand. They have so much wind. Wind tends not to blow when the power is most needed. That is just the way it is that I have discovered in my own research. So those are significant problems, yes.

Mr. GRIFFITH. And that can affect jobs; can it not?

Mr. LESSER. Absolutely.

Mr. WHITFIELD. The gentleman's times has expired.

Mr. GRIFFITH. Thank you, Mr. Chairman. I yield back.

Mr. WHITFIELD. At this time I recognize the gentlelady from California Mrs. Capps for 5 minutes.

Mrs. CAPPS. Thank you, Mr. Chairman.

And thank you to our witnesses, each of you, for your testimony.

You know, we all know that America's power is generated by many different sources, to be sure, but we also know that fossil fuels make up the overwhelming majority of our Nation's energy supply. Today is the third subcommittee hearing held this year on the sources of fuel used for electricity generation in the United States, but we have yet to hold a hearing examining the consequences of our dependence on fossil fuels. This is more than an odd note, considering that we are already seeing the very real impacts from this dependence on fossil fuels: rising sea levels, severe droughts, extreme weather, and superstorms. Climate change is very real and is already causing serious problems that demand action. In addition to obvious environmental damage, these storms, droughts and wildfires are having a significant economic impact.

And, Mr. Weiss, could you share with us briefly—I want to ask you a couple more questions, too—some of the documented research of how climate change is affecting our economy?

Mr. WEISS. Thank you, Representative Capps.

Yes. We analyzed the $25 billion in damages extreme weather events over the past 2 years, including the drought in Texas and the Southwest, and found that the total economic damages were $188 billion. In addition, the federal government spent $136 billion on disaster relief and recovery over those same periods, which is about $400 per household per year for disaster relief and recovery.

Mrs. CAPPS. Thank you.

In your testimony today, you stated, and it is a quote, Because the Federal Government pays for a major share of disaster recovery, investing in resiliency now will help protect taxpayers from more deficit spending in the future.

This is actually rather counter to what we often hear about the value of investing in our country. Could you elaborate on this just briefly? How can predisaster mitigation spending actually save taxpayers money in the long run?

Mr. WEISS. Well, the Federal Emergency Management Agency found that by investing $1 in disaster resilience, or what they call predisaster mitigation, that reduces damages by $4. And so, for example, your efforts to get more investments in disaster resilience will help save us money in the long run by a ratio of about 4 to 1, according to FEMA.

Mrs. CAPPS. Thank you.

One more question, if I—yes, I have time.

Especially in these tough fiscal times, we certainly need to be allocating tax dollars more effectively at all levels of government. Many States and localities understand the long-term benefits you have discussed and are eager to implement mitigation projects. The problem is, however, they can't afford it.

I believe the broad public benefit in cost savings alone create a compelling national interest for the Federal Government to help our local communities plan and implement predisaster mitigation efforts, and that is why I sent a letter to the President earlier this year with 39 of my colleagues, including several members on this committee, urging him to take action on this issue. And I was pleased to see the President's fiscal year 2014 budget include $200 million for climate mitigation projects, but this really only scratches the surface of what is needed.

So, Mr. Weiss, again, there is an estimate of how much funding is needed for these projects nationwide. Would you share some information around that topic with us?

Mr. WEISS. Well, the Congressional Research Service was looking at this for the utility industry, and they found that the American Society of Civil Engineers estimates we need to spend over $600 billion between now and 2020 to make our utility system more resistant to disruption from extreme weather. But they could not find another estimate besides the ASCE one about it, and so that is something we need to do, which, again, in your letter to the President you recommended.

It is important when looking at the costs of natural gas and coal-generated electricity that those fuels include the external economic costs of their use, which includes climate change and extreme weather linked to climate change. Otherwise society is in effect subsidizing the use of coal and natural gas by paying these costs for damages from extreme weather and then the taxpayers paying, you know, $400 a household for disaster relief and recovery.

Mrs. CAPPS. We need to shift our attitude. And I appreciate your comments. This is a major problem, I know. Our energy committee, Energy and Commerce Committee, I think, is tasked with something that can't be solved overnight, but we need to start moving in that right direction.

So, Mr. Chairman, I hope this committee will begin to examine the realities of climate change, and what we can do, and what our obligations here in this committee are to minimize its impacts.

I yield back.

Mr. WHITFIELD. Thank you, Mrs. Capps.

At this time I recognize the gentleman from Texas Mr. Barton for 5 minutes.

Mr. BARTON. Thank you, Mr. Chairman. And I appreciate you and Mr. Rush holding this hearing.

At a previous hearing earlier this year, one of our witnesses Mr. Gramlich was here representing the wind association, and I asked him some question about production tax credit impacting negative prices into the grid and ERCOT, and to his credit, we asked some questions on the record, and he did answer. My staff was a little bit puzzled by the answers, because they don't conform with the information that we have at the staff level, but I do admit that you can look at data and interpret it different ways. So instead of revisiting those questions directly to Mr. Gramlich, I am going to ask Dr. Lesser, who is sitting next to him, to take a crack at it.

So, Dr. Lesser, the issue is the production tax credit for wind, which I supported when it was initially proposed, because wind power was a startup, struggling sector of the energy economy, and I felt it was fair to help give it some production tax credits to get it off the ground. I think it is a more difficult proposition now, because wind power is firmly established and is a significant part of the generation system in States like Texas.

So my question to you, Doctor, do you think the production tax credit impacts the way market prices are in ERCOT in Texas, and do you think that it should be allowed to use production tax credit to bid negative into the grid, which has happened, although it is disputable how often it has happened?

Mr. LESSER. Thank you, Mr. Barton.

No, I do not think that wind operators, anyone receiving the PTC, should be eligible to bid negatively. There is no reason for that. Studies by the Northridge Group show that negative prices are far more prevalent than have been indicated. Those negative prices are affecting the viability of conventional generators, which has an effect on reliability. As far as the PTC going on, you now have these direct subsidies and mandates for 35 years since PURPA was passed.

One of the arguments you will often hear is that the wind industry requires additional subsidies to be cost competitive, yet earlier on we hear wind is competitive, that it is cheaper. The problem with that, well, if it is cheaper, why do you continue to need subsidies?

The other issue I would raise is that if—the problem is what you are doing is you are distorting the market so much by having a subsidy that is, in fact, greater than the average market price in many areas—for example, the price in PJM that serves D.C. as well as much of the Upper Midwest and Atlantic States was less than the $35 value of the PTC last year. When you have a subsidy that is larger than the average market price, that introduces huge economic distortions. In the long run, that drives out investment of other resources. That means that consumers will end up paying higher prices. They will not—again, it is simply an economic fallacy to say that you can subsidize your way to greater economic growth, lower prices. It just cannot happen.

Mr. BARTON. Is there a way, absent eliminating the production tax credit, to change the rules to prevent using that subsidy to bid into a competitive market, or is the only way to prevent it is to eliminate the subsidy?

Mr. LESSER. Well, I think the easier way to prevent it is to just eliminate the subsidy. There may be ways. FERC could oversee markets and change the way resources are allowed to bid that receive the subsidy, but my preference would be the simpler approach, which is just eliminate the subsidy, then you eliminate the problem entirely.

Mr. BARTON. I think in fairness I should give Mr. Gramlich an opportunity to counterpoint what Dr. Lesser just said.

Mr. GRAMLICH. Thank you.

I mean, the ability to occasionally bid negative is, of course, available to all resources on the grid, and there are conventional power plants that do so at times, and they also receive a variety of federal incentives. So if any such line of policy inquiry is pursued, we would urge that they not single out wind.

Mr. BARTON. Well, that is a true statement, but the problem is that with respect to wind power, you are using a Federal subsidy of the taxpayer. If somebody with private capital bids negative, they are risking shareholder equity, they are not using a Federal subsidy directly. With that——

Mr. WHITFIELD. The gentleman's time has expired.

At this time I will recognize the gentlelady Dr. Christensen for 5 minutes.

Mrs. CHRISTENSEN. Thank you, Mr. Chairman. And I thank you and the ranking member for holding this hearing. It has been very informative, as we in the Virgin Islands work to transition to cleaner, less expensive fuel.

During the hearings the subcommittee has had on challenges to electric reliability, we haven't heard much about how climate change is already affecting electric utilities. We are beginning to hear some of that today. And, of course, with my district being in the path of hurricanes every year, it is a serious concern to me as we can expect stronger storms, I think, which will affect our utility. And our utility is already struggling to keep lights on. Just yesterday we had power outages, and that is an every-other-day occurrence in St. Thomas.

We know that climate change, Mr. Weiss, will mean more heat waves, droughts and wildfires. Are there examples of these kinds of extreme weather events impairing the operation of power plants?

Mr. WEISS. Thank you.

Yes, there are. From last summer's drought, at least four states, California, New York, Illinois and, I believe, Colorado, but let me check on that, did experience disruption of their power plants because they couldn't get enough cooling water to make the plants run. I am sorry, it was Connecticut. California, Connecticut, Illinois and New York.

And it is interesting that the draft National Climate Assessment predicts that future climate change is going to interfere with electricity generation. Let me just quote from them; quote, "These infrastructure systems, including electricity, will be affected by various climate-related events and processes."

So what is past is prologue in terms of climate change disrupting the operation of power plants.

Mrs. CHRISTENSEN. And if we fail to act, and climate change continues unabated, extreme weather events would be expected to become more frequent and more disruptive?

Mr. WEISS. Yes. The National Climate Assessment also predicts that there will be an increase in extreme weather events, droughts, floods, storms, heat waves and wildfires.

Mrs. CHRISTENSEN. All right. And, you know, in addition to the storms, I live on islands, and this was one of the articles from our newspaper yesterday.

So both of my power plants are located near shorelines, so the rising sea level is another threat in addition to the storms. So if we are concerned about the reliability of our electric grid and government spending, we really need to address climate change.

Mr. Weiss, has the National Academy of Sciences or any other scientific institution determined that we are currently on track to avoid dangerous climate change?

Mr. WEISS. They have—I don't believe National Academy of Sciences has addressed that. However, if you look at how much emissions have gone down, the Environmental Protection Agency said we have had a 7 percent decline in overall greenhouse gas pollution since 2005. The President committed us to a 17 percent reduction by 2020. So we are reducing our emissions; however, the Energy Information Administration predicts that, although emissions are going to go down between now and 2017, they will begin rising again in 2017. So, no, we do not appear to be on track to avoiding the worst impacts of climate change.

Mrs. CHRISTENSEN. Well, reducing our carbon pollution by the amount necessary to avoid dangerous climate change, I assume, will require the power sector, as we have been talking about, to transition to cleaner technologies. Is that transition happening fast enough? And why are we on track to start to go up again in 2017?

Mr. WEISS. We are on track to go up again in 2017 because of the increase in electricity generation expected from fossil fuel sources, even though we are also going to be increasing our renewable generation between now and then.

What we really need to do is to require the power plants, existing power plants, to reduce their carbon pollution either through legislation, which would be many people's preferred option, or, failing that, the Environmental Protection Agency setting standards to do that. That would get us close, but not reach the President's 17 percent reduction goal by 2020.

Mrs. CHRISTENSEN. And, you know, just in closing, and I say this all the time, but we talk about the costs of electricity. We are very concerned about costs, and so a lot of times the talk turns to coal or fossil fuels, but the costs in terms of public health is something that we never take into consideration, the longer-term costs. And so cost is more than just the cost of the fuel, it is the cost of the impact to our communities, to the health of our children.

And with that, I will yield back my time.

Mr. WHITFIELD. The gentlelady's time is expired.

At this time I recognize the gentleman from West Virginia Mr. McKinley for 5 minutes.

Mr. MCKINLEY. Thank you, Mr. Chairman. In deference to the time, I am going to try to get a couple questions in; then I would like to yield some time to my colleague from Colorado.

First, Mr. Sypolt, I want to thank you for your investment in the development of the Marcellus shale, shale gas, and what you are doing in West Virginia.

What do you think—do you think that could lead to more gas turbine development, electric power generation in West Virginia or around the country?

Mr. SYPOLT. Well, absolutely I do, Congressman. The Marcellus shale is extremely real. Three years ago you hardly had any production; today it is 10.4 Bcf a day. I mean, so it is extremely real. And clearly when you have, you know, cheap energy, you have the opportunity to use that and, you know, to have turbines to develop or produce additional electricity. You know, those can certainly be set in West Virginia or in other surrounding states where they have good access to the Marcellus shale, so—and I think that asset——

Mr. MCKINLEY. Does that add to more——

Mr. SYPOLT [continuing]. Is going to continue to grow.

Mr. MCKINLEY. That will only strengthen more of the reliability of the grid if we could——

Mr. SYPOLT. Absolutely.

Mr. MCKINLEY. So secondly, and continuing this same line of questioning, if—and you have heard earlier from some of the comments made about the subsidies to the fossil fuel, coal, oil and gas. If we were to eliminate those subsidies, what effect would that have on the grid?

Mr. SYPOLT. You know, I don't know that I am really the best one to answer that, you know, but I would say that, you know, Dominion has all forms of energy, Congressman, as I mentioned earlier. You know, we are also looking at wind, you know.

Mr. MCKINLEY. Well, let us look if any others would like to add. If we were to eliminate the subsidies for all renewables and fossil fuels, what effect would that have on the grid reliability?

Mr. LESSER. I would be happy to answer that——

Mr. MCKINLEY. Please.

Mr. LESSER [continuing]. Sir. I don't think there would be any adverse impact on reliability. I think what you would see is much more efficient investment in generating resources for the long term, and it would be easier to integrate resources onto the grid. You would have less investment in subsidized intermittent generation. However, the subsidies—when you look at the subsidies in contrast to on a total-dollar basis, as Mr. Gramlich has done, but look at it on a per-megawatt-hour basis, the Energy Information Administration has issued reports saying that intermittent resource subsidies are far greater, you know, in combining both that PTC and our requirements to use through renewable portfolio standards. So

I don't think there would be any adverse impacts. I think the grid would actually benefit.

Mr. MCKINLEY. Thank you.

Mr. Chairman, I would like to yield back the balance of my time, then, to my friend from Colorado.

Mr. WHITFIELD. OK. The gentlemen yields to the gentleman from Colorado.

Mr. GARDNER. I thank my colleague from West Virginia. I appreciate you yielding time.

Mr. Gramlich, there was a question I think that you had received from Mr. Waxman that I wanted to clarify a little bit if I could. I have been a strong supporter of renewable energy and certainly wind resources where it makes sense, and I try to make sure that we are doing so from a—as market-based policies as we can. And I think the question was about whether or not there was backup baseload generation required for wind, and I believe your answer was there is not—there is no baseload backup required.

Mr. GRAMLICH. There are reserves required for wind, and coal, and gas and all resources. All resources have the potential to go off at any moment. And ever since we have had a power grid, we have had backup across the grid that fills in in case any resource goes offline.

Mr. GARDNER. And thank you. I just want to restate some of the testimony in a committee hearing earlier this year with Mr. Moeller from the FERC, Chairman of the FERC Commission, talking about backup wind generation. He said that—I asked the question, so for every 5 megs, you need 4 megs of baseload in some instances. And he said that that is correct.

So, I mean, certainly that was what Mr. Moeller at FERC had testified before this committee.

Mr. GRAMLICH. I would love to have the opportunity to perhaps provide written testimony in response to that.

Mr. GARDNER. Sure. I mean, do you think he was wrong when he said that?

Mr. GRAMLICH. Yes. There is a tiny incremental addition of reserves needed to bring on new wind, and it is, in fact, no greater than what is needed when new conventional sources are brought onto the grid.

Mr. GARDNER. Well, I would be interested in hearing if the commissioner was correct.

Mr. GRAMLICH. I know him well. We will be happy to discuss, yes.

Mr. GARDNER. Mr. Weiss, do you think hydropower is a renewable energy?

Mr. WEISS. Yes, it is.

Mr. GARDNER. One of the concerns I have, in Colorado they passed a Senate Bill 252 at the state legislature that requires rural cooperatives to increase their renewable energy standard to 25 percent. They get approximately 12 percent of its power needs from WAPA, which gets tremendous amount of its power from Federal Hydropower. That is where WAPA gets it power, Federal Hydropower, yet none of that power is counted under the Colorado Renewable Energy Standard because it is hydropower. It is not considered a renewable energy resource. Do you think we should change the law in Colorado to include Federal Hydropower since it is a renewable energy resource in your mind?

Mr. WEISS. I would leave that to Coloradoans to decide.

Mr. GARDNER. But if you were there, you would say, yes, it is renewable?

Mr. WEISS. If I was there, I would look at the whole panoply of resources. I think the reason——

Mr. GARDNER. You just said renewable, you thought Federal Hydropower is renewable.

Mr. WEISS. Yes. I think the reason why some people do not consider it renewable is because there are upstream impacts from building dams. I think what we ought to be doing is retrofitting existing dams with much more effective turbines, and that ought to be included as renewable.

Mr. GARDNER. Thank you, Mr. Chairman.

Mr. WHITFIELD. Gentleman's time is expired.

At this time, I recognize the gentleman from California, Mr. NcNerney, for 5 minutes.

Mr. MCNERNEY. Thank you.

Mr. WHITFIELD. Then we have a vote on the floor, so after his questions, we are going to terminate this rather quickly.

Mr. MCNERNEY. Thank you, Mr. Chairman.

Wind energy comes on and off on it slowly because on a large scale windmill, you have hundreds or maybe thousands of large windmills over hundreds of square miles. If one or two comes on or shuts off, it has very little impact, so over time and over space, that impact of coming on and off is very slow and gradual, so it doesn't really affect the grid like shutting down a large power plant. I just wanted to make sure that I had an opportunity to say that.

Mr. Cicio, I certainly enjoyed your testimony, but it was a little confusing in a sense, and let me explain why. I understand your concerns about lack of Federal oversight on natural gas pipeline reliability, but often we hear from industry, we hear from the other side that oversight, Federal oversight is a problem; we need to let the market straighten things out. So my question is, is this—do you propose the lawmakers create regulations to keep customers safe while also taking note of business considerations—is there a way we can do that here? Is that too big of a broad of a——

Mr. WEISS. Remember who we are. We are consumers. We have a different perspective. We are the companies that rely upon reliability of that grid, and we see that there is an agency that is overseeing electric reliability nationwide, and that is NERC. We do not see an organization that is looking at pipeline reliability, for example, at peak demands.

The pipelines in this country, and the regulations are very good. What has changed is the market. The market has changed. We have, over a 4-year period of time, significant changes to coal-fired power generation, new natural gas coming on. We have the industrial renaissance happening that is going to increase natural gas demand on those same pipelines.

Mr. MCNERNEY. So, it is from a customer's point of view, there is a need for——

Mr. WEISS. Yes.

Mr. McNERNEY [continuing]. Oversight. To make sure that these things are reliant.

Mr. WEISS. Shame on us if we don't know if there is a pipeline reliability issue.

Mr. McNERNEY. Thank you.

Mr. Weiss, in your testimony, you mentioned that climate change causes increased instances of extreme weather events which in turn threatens electrical reliability. Do you think that that—we simply need to invest in better infrastructure, or how would we best move forward to improve reliability in face of these extreme events?

Mr. WEISS. I think we need to do two things. First, we need to reduce the carbon pollution and other emissions that are responsible for climate change. As I mentioned earlier, we are making progress but not nearly fast enough to avert the worst impacts of climate change, but second, we do need to improve the resiliency of our infrastructure. Representative Capps has proposed creating a commission to do that that would look at how much money we need and identifying a dedicated source of revenue to pay for it, and I would support that proposal.

Mr. McNERNEY. Thank you for your brief answer.

Mr. Shelk, how much—just my own curiosity, how much of any do coal—of gas-powered power plants, how much gas do a typical plant keep on sight, if any?

Mr. SHELK. Obviously, gas is different from storing other fuel.

Mr. McNERNEY. Yes.

Mr. SHELK. Some do actually have, in the northeast, LNG Storage, and one of reasons why New England has problems that the rest of the country does not have is because the geology of New England doesn't allow for gas storage. Gas is usually only stored underground. That is Mr. Sypolt's business. The plant itself would not store gas, per se, except in certain situations where there are LNG facilities nearby, but many of the plants that are gas fired are also dual fuel with oil and so that is one of the major sources of power at peak time in New England is the dual fuel plants.

Mr. McNERNEY. Do you think we can create a broad policy on a Federal level that provides adequate flexibility to regional overseers?

Mr. SHELK. I do. I think actually FERC is going about it the right way. They are approaching this, as you heard in the prior hearings, with regional hearings, technical conferences. They are holding all of us—our feet to the fire, and I think we do have that infrastructure.

With all due respect to Mr. Cicio, he misunderstands NERC. NERC does not order the development of electric or gas assets, so I would argue that NERC actually is the natural gas reliability entity in the same way because they are drawing attention to these issues. Their Phase II report will be out very shortly. I think the committee can rest assured that you have the regulators and the grid operators and all of us in the market very, very in tune to these issues and we are going to solve them.

Mr. McNERNEY. Thank you.

I yield back, Mr. Chairman.

Mr. WHITFIELD. Thanks very much.

And that terminates today's hearing. Once we adjourn, Mr. Shelk and Mr. Cicio can get together and talk this out. But we appreciate the testimony that all of you gave, and we continue to look forward to working with you on grid reliability and integration cost.

And with that, without objection, I will enter into the record a statement from the Natural Gas Council and the American Public Power Association.

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

Mr. WHITFIELD. The record will remain open for 10 days, and some of you will be receiving some additional questions. We would appreciate your response, and so thank you, once again. The hearing is now concluded. Thank you.

[Whereupon, at 11:05 a.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

NATURAL GAS COUNCIL

May 8, 2013

Honorable Ed Whitfield, Chairman
Subcommittee on Energy and Power
Committee on Energy and Commerce
2368 Rayburn House Office Building
Washington, DC 20515

Honorable Bobby Rush, Ranking Member
Subcommittee on Energy and Power
Committee on Energy and Commerce
2268 Rayburn House Office Building
Washington, DC 20515

Dear Chairman Whitfield and Ranking Member Rush:

The Natural Gas Council believes that the overall goal of gas-electric coordination efforts should be to preserve and, where appropriate, enhance reliability for all customers, both natural gas and electric. Natural gas resources in North America are abundant and provide an opportunity for the natural gas industry to provide solutions for many of our country's energy needs, including the direct use of natural gas in homes and businesses, as a feedstock in manufacturing, and as a fuel for electric generation.

The key to realizing the full value of natural gas is the continued development of a robust natural gas infrastructure along the entire value chain so that natural gas can be delivered wherever and whenever it is needed to those who value it the most. Accordingly, the increased use of natural gas for electric generation should be accompanied by appropriate investments in the natural gas infrastructure needed to meet the needs of all customers on the natural gas system, and the costs of such investments must be borne by those who caused the costs to be incurred. In that regard, electric market rules should provide adequate incentives, *e.g.*, through appropriate cost-recovery mechanisms, for electric generators to ensure the adequacy and reliability of their fuel supplies. For natural gas-fired generators this may mean firm gas supply contracts, portfolio management, firm transportation capacity on interconnected pipeline(s), storage or other services to balance load variations, dual-fuel capability with on-site alternate fuel storage, or some combination of the above. The adequacy of a generator's fuel supply should be a factor in considering whether the generator is "reliable" for electric reliability purposes.

Sincerely,

R. Skip Horvath

Skip Horvath
President
Natural Gas Supply Association

Dave McCurdy

Hon. Dave McCurdy
President & CEO
American Gas Association

Barry Russell

Barry Russell
President & CEO
Independent Petroleum Association of America

Don Santa
President
Interstate Natural Gas Association of America

Marty Durbin

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APPA

May 9, 2013

The Honorable Ed Whitfield
Chairman
Subcommittee on Energy and Power
Energy and Commerce Committee
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Whitfield:

The American Public Power Association (APPA) welcomes the opportunity to submit this statement for the record in relation to the House Energy & Power Subcommittee hearing on "American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape."

APPA is the national service organization representing the interests of over 2,000 municipal and other state- and locally-owned, not-for-profit electric utilities throughout the United States (all but Hawaii). Collectively, public power utilities deliver electricity to one of every seven electricity consumers (approximately 47 million people), serving some of the nation's largest cities. However, the vast majority of APPA's members serve communities with populations of 10,000 people or less.

Overall, public power utilities' primary purpose is to provide reliable, efficient service to local customers at the lowest possible cost, consistent with good environmental stewardship. Public power utilities are locally created governmental institutions that address a basic community need: they operate on a not-for-profit basis to provide an essential public service, reliably and efficiently, at a reasonable price.

Greater Use of Natural Gas and Renewables for Electric Generation Will Impact Utility Operations and Potentially Impact Grid Reliability

APPA commends you for holding a hearing on the issues surrounding the greater use of natural gas and intermittent renewables as fuel sources for electric generation. APPA members are impacted by the greater use of these fuel sources and will likely experience a variety of operational issues as they bring more of these resources online. The shift from coal to natural gas for electric generation creates several challenges that must be addressed, including potential price volatility for utilities and their customers, inadequate pipeline capacity and storage, lack of flexibility in pipeline rate schedules to accommodate the needs of electric generation, and misalignment of, and lack of intra-day flexibility within, the gas and electric days.

Greater use of intermittent renewables, such as wind, creates additional challenges from an operational standpoint. Because electricity must be generated and used simultaneously, the type of fuel used to generate must be accessible at all times. Therefore, when the wind does not blow or the sun does not shine, back-up power must be available to make up for the loss of the power being generated by those variable or intermittent sources. In the absence of substantial electricity storage facilities, the only such reliable back-up power is coal, natural gas, oil (which is only used sparingly in power generation), and, in some cases, hydropower. Nuclear power is extremely reliable in terms of being able to be used almost continuously for months at a time at close to 100 percent, but it is not able to be ramped up and down quickly for extended periods of time, so is not well-suited to follow the fluctuations in wind and solar generation. Therefore, as coal is pushed out of the resource mix because of environmental constraints, the most heavily used resources to back up wind and solar are and will be natural gas and hydropower. Since hydropower is not available everywhere, the principal fuel source for this type of back-up power nationwide is natural gas.

Given these trends, it is important that Congress continues to examine the short- and long-term implications of federal policies that promote more use of natural gas and intermittent renewables as fuels for electric generation on electricity prices and grid reliability.

Natural Gas Is Becoming the Dominant Fuel Source for Electric Generation

As the subcommittee is well aware, there are a variety of factors driving electric utilities away from the use of coal-fired generation. The Environmental Protection Agency (EPA) has issued several regulations, such as utility Maximum Achievable Control Technology (MACT), that are driving utilities to retire coal-fired power plants and replace them with natural gas-fired ones. At the same time, the low cost of natural gas in the U.S., due to increased production, is making the use of coal for generation less economic, particularly when factoring in the regulatory landscape. Just a few years ago, coal was the predominant fuel type used for electric generation. Today, its share has declined as electric generation from natural gas and renewables, such as wind and solar, increase. The use of coal for electric generation in the U.S. will further decline when EPA finalizes its New Source Performance Standards (NSPS) for greenhouse gas (GHG) emissions from new power plants.

A January 2013 APPA report examining new generation capacity in the U.S. highlights these trends in the industry. It finds that "the share of coal-fired capacity continues to diminish, as solar and nuclear, in addition to wind and natural gas, have surpassed it in the under construction category."[1] Over 40 percent of new plant construction is natural gas, with 19.1 percent wind, 12.7 percent solar, and 11.4 percent nuclear.[2] In addition, since 2007, the share of coal plants under construction has dropped dramatically. The report also notes that natural gas has the largest share of operating capacity (43.4 percent), with coal at 30 percent.[3] The operating capacity of coal will continue to drop as more coal-fired plants are retired due to age, EPA regulations, and the generally lower price of natural gas. In 2012 alone, over 12,200 MW of capacity was retired. Two-thirds of those retirements were coal-fired.[4]

There will be long-term implications from the greater use of natural gas for electric generation. Utilities are spending hundreds of millions of dollars to convert existing coal facilities, where possible, to natural gas or to construct new natural gas plants. They are also using natural gas generation to back up wind and solar power, which are, as mentioned above, variable energy sources that cannot be relied on to generate power at all times. These are long-term investments being made to generate cleaner power, but they increase the risk of greater volatility in electricity prices for consumers, and potentially reduce electric reliability. As a commodity, natural gas is subject to price volatility. Prices may be low today, but can easily rise in the years to come due to a variety of factors including potential new or existing regulations on hydraulic fracturing, increased utility and industrial demand, exports, and increasing use in the transportation sector.

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[1] *See* APPA Report on New Generating Capacity: 2013 Update, January 2013, available at http://publicpower.org/files/PDFs/New_plants_analysis_2013.pdf
[2] *Id.* at 2.
[3] *Id.* at 15.
[4] *Id.* at 17.

In addition, it is not clear yet whether there will be sufficient infrastructure or storage to accommodate the greater use of natural gas by electric utilities.[5] While the Federal Energy Regulatory Commission (FERC) is examining how to promote greater coordination between the electricity and natural gas industries, no one knows whether all the changes needed for fuel switching on this scale can be accomplished in the time needed to comply with EPA regulations. As is evidenced in New England, a region of the country heavily dependent on natural gas for electric generation, there are issues with pipeline capacity and competing demand for gas for home heating. Electricity prices in the region were four to eight times higher than normal in February 2013 because of the lack of fuel diversity.[6]

New England is not the only region of the country with potential reliability concerns. A January 2013 EPA Compliance Update by the Midwest Independent System Operator (MISO) states the ISO has concerns about whether there is sufficient resource adequacy in the Midwest beginning in 2016. With the significant number of coal-fired generation units retiring due to EPA regulations and low natural gas prices, MISO projects there will be a potential 11.7 GW shortfall of resource adequacy in the winter of 2016 and a 3.5 GW one in the summer of 2016.[7] MISO anticipates increased utilization of natural gas fuel generation that will result in "changes to the system's generation configuration and concerns about the ability of the current pipeline infrastructure's ability to deliver enough gas."[8] On March 19, 2013, the Committee heard directly from representatives of ISO-New England and MISO about these and other challenges regional grid operators face and potential electric reliability impacts.

There are also market-related challenges arising from greater use of natural gas for electric generation. Electric utilities are concerned about the misalignment of, and intra-day flexibility within, the gas and electric days and the range of pipeline service offerings available to accommodate generator needs (e.g., flexibility of pipeline rate schedules). They are also concerned about the lack of sufficient communications between the two industries and how efforts to improve communications going forward could potentially violate FERC's Standards of Conduct (SoC). It is unclear to both industries what type of information they can share with one another without running afoul of the SoC. Many of these issues are solvable, but will require time to do so. Congressional oversight of these challenges is needed to ensure they are addressed.

Electric Generation from Renewables Is Increasing and Creates Unique Operational Challenges

The amount of electric generation from renewable or variable energy resources (VERs) is increasing throughout the U.S. The primary driver of increased use of VERs is state renewable portfolio standards (RPS) that mandate that utilities generate electricity from a certain percentage of designated renewable resources. These resources vary by state, but generally include wind, solar, geothermal, biomass, and certain types of hydropower. According to the U.S. Energy Information Agency, 30 states and the District of Columbia have mandatory RPSs and another seven have voluntary goals for renewable

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[5] A July 2010 APPA Study by the Aspen Environmental Group, Implications of Greater Reliance on Natural Gas for Electricity Generation, examines the impacts on natural gas and deliveries to electric utilities from fuel switching.
[6] *See* In New England, a Natural Gas Trap, New York Times, February 15, 2013, available at http://www.nytimes.com/2013/02/16/business/electricity-costs-up-in-gas-dependent-new-england.html?_r=0
[7] See MISO EPA Compliance Update, January 11, 2013, available at https://www.misoenergy.org/Library/Repository/Communication%20Material/Power%20Up/EPA%20Compliance%20Update.pdf.
[8] https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/EPACompliance.aspx

generation (as of January 2012).[9] Other policies driving increased use of renewables include market conditions and federal incentives, namely federal tax incentives.

While most APPA members are not directly subject to state RPSs, many have as a policy matter added renewables to their generation mix in states where RPSs are mandated for investor-owned utilities. Reasons for doing so include the promotion of fuel diversity, community desire to promote clean energy, and state policies or incentives. Wind and solar are the dominant renewables used by public power utilities for generation, and their use continues to grow. APPA members using these renewable resources face a variety of operational challenges, particularly with the use of wind power, due to their intermittency.

The electric grid is designed to provide real-time power to meet demand. Electricity generated from renewable resources can vary widely based on the time of day and season of year. Solar power is generated during the day, when electricity demand is higher. However, the opposite tends to be true with wind power. The wind tends to blow more at night and during the spring and fall when electricity demand is lower. As more wind power is integrated into the grid, this variability can cause operational challenges that impact grid stability. When the wind generates more power than is needed, utilities undertake a variety of measures to manage that power and ensure system stability.

When the wind does not blow, its production has to be replaced with another fuel source, which is typically natural gas, as mentioned above. Most wind generation is backed up with natural gas turbines (either simple cycle or combined cycle) that can ramp up or down based on the production output of the wind power. Utilities have to carefully monitor weather forecasts to determine when the wind might blow and be able to dispatch backup generation in a short time frame to provide power when the wind is not blowing. They also have to work closely with balancing authorities to ensure that transmission is available to move power to meet customer demands for power.

While technological improvements to natural gas turbines that back up wind generation will address some of the problems associated with ramping, such as reduced turbine efficiency and increased emissions of certain pollutants, utilities will still face many challenges from the integration of wind power into the grid. Transmission of power from remote areas to population centers to serve customer demand is another problem with no simple solution. There are strong disagreements about who should pay for the construction of transmission lines that bring renewable power into the grid and issues surrounding the siting of such lines.

In addition to these challenges, there is the issue of the federal renewable electricity production tax credit (PTC). Created by Congress in the Energy Policy Act of 1992 to promote the use of renewables, it provides tax credits of varying amounts for each kilowatt hour (kWh/h) of electricity generated from eligible technologies. For wind, the credit is currently 2.3 cents per kWh. The PTC is widely credited with the development of the wind industry in the U.S. There is, however, ongoing debate today about whether the PTC is still necessary to support the wind industry's continued development.

It is important for the subcommittee to evaluate all federal policies designed to promote renewable energy. Many of these policies have served the important goal of fostering research and development of clean energy technologies. With some of these technologies having become more commercially viable and competitive with other generation sources, now is a good time to evaluate whether these policies still make sense or should be modified.

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[9] See "Most States Have Renewable Portfolio Standards," U.S. EIA, Today in Energy available at http://www.eia.gov/todayinenergy/detail.cfm?id=4850.

For example, wind developers in the Northwest sued the Bonneville Power Administration (BPA) when it curtailed wind power on its transmission lines in 2011 because of significant amounts of water in the Columbia River power system. With so much water to generate hydropower and a lot of wind, there was far more power than needed to meet load. Hydropower generation in the Columbia River basin is governed by a strict set of environmental laws to protect fish, so BPA had to maintain the hydropower flows in order to ensure protection of those resources.

APPA members, in incorporating renewable generation into their resource portfolios, need the ability to evaluate specific renewable projects against one another and against distributed generation and energy efficiency/demand response measures. Subsidies given to certain types of renewable generation can skew individual utility integrated resource planning processes and, on a macro level, our nation's overall resource choices, leading to sub-optimally efficient resource outcomes. Therefore, it is important that Congress evaluate federal energy policies in order to ensure that we are able to maximize our domestic generation resources.

Thank you again for this opportunity to submit a statement for the record and we welcome any questions you might have.

Sincerely,

Mark Crisson

Mark Crisson
President & CEO

cc: The Honorable Bobby Rush
The Honorable Fred Upton
The Honorable Henry Waxman

Electric Power Supply Association (EPSA)
Response to Question from May 9, 2013 Hearing
US House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy and Power

American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape

The Honorable Gene Green

1. **You talk about how the electric/gas challenge varies by region and thus a regional approach is preferable to a top down federal solution. You go on to say that FERC should be commended for its attention to these issues in a thoughtful manner. Can you please elaborate?**

Response by Mr. John E. Shelk, President and CEO, EPSA

FERC wisely recognizes that the challenges faced in addressing electric and natural gas coordination issues vary widely on a regional basis due to a number of important factors. These factors include differences between regional fuel-resource mixes, renewables development, access to and development of the natural gas pipeline transportation system, whether a power plant obtains natural gas directly from a pipeline or through the local gas utility, access to imported natural gas, geology and geography, proximity to shale gas development and/or natural gas storage, and access to power imports from adjacent markets. Thus, FERC convened a series of regional conferences in 2012 reflecting these regional differences. The differing presentations from a wide range of stakeholders across regions at these conferences proved the regional nature of the electric and natural gas coordination issues. Based on this information, to its credit FERC has not imposed the one-size-fits-all approach of mandating that all natural gas electricity suppliers enter into the type of long-term contracts with interstate gas pipelines that the pipelines have advocated.

A critical difference between regions relates to wholesale and retail market designs. The ability for competitive generators to include natural gas costs, including for transportation, varies from region to region. While the "organized markets" with regional transmission organizations (RTOs) provide the least cost, most economically efficient electricity supply to consumers, cost recovery for fuel supply and transportation is not guaranteed under this market structure. In fact, in some regions competitive suppliers are not able to include actual updated natural gas costs in their wholesale market bids. As to retail market design, New York and most of the states in New England and the PJM Interconnection allow customers to shop for the best deal by choosing among multiple competitive retail suppliers. In these regions it is not feasible for a wholesale power supplier to enter into long term firm transportation contracts with interstate gas pipelines given the short term nature of the competitive retail arrangements.

A significant level of effort is underway at the regional level to consider these issues through existing regional power market structures. This includes through table-top exercises, planning studies, general education, efforts to enhance communications, and consideration of reforms to specific regional electric market rules. Some areas of the country, such as New England, are facing these issues on a more acute basis and are further along in responding. In addition to several ongoing regional initiatives, the Independent System Operator for New England ("ISO-NE") has already filed and received approval from FERC as to proposals addressing communications and scheduling. ISO-NE is considering other market rule changes with stakeholders.

In terms of FERC's specific activities, the electric-natural gas coordination issues have been an area of focus by FERC Commissioners and staff for several years, including informal staff outreach. A general administrative proceeding was established in February 2012 on the interdependency of and coordination between the electric-natural gas industries (*Coordination Between Natural Gas and Electricity Markets*, Docket No. AD12-12-000). The Commission received seventy-nine sets of comments from industry stakeholders, including from EPSA and various EPSA member companies. This was followed by five regional conferences held in August 2012 to consider scheduling and market structures/rules; communications, coordination, and information sharing; and reliability concerns. A wide range of industry representatives participated and/or attended these conferences, with the total attendance exceeding 1,200 registrants.

On November 15, 2012, FERC issued an Order that directed: (1) staff to convene two technical conferences (one on Information Sharing and Communications and the other on Gas-Electric Scheduling and Capacity Release), (2) the RTOs to report on the progress of their regional efforts, and (3) staff to provide updates to the Commission at least once each quarter for 2013 and 2014. Concurrently, FERC issued a Staff Report on the five regional technical conferences held in August 2012.

On February 13, 2013, FERC held the Information Sharing and Communications conference and on April 25, 2013, held the Scheduling and Capacity Release conference. Additionally, on March 21, 2013, FERC staff provided the first quarterly update to the Commission on gas-electric coordination activities highlighting national and regional initiatives, relevant filings and the additional technical conferences.

On May 16, 2013, FERC convened a special meeting and heard an update from a representative of each of the seven RTOs. As a follow-up, on June 4, 2013, a letter was sent to all the RTOs by Commissioner Philip Moeller with additional questions and asking whether there were specific actions FERC should take to address concerns or facilitate improvements. The RTOs are to provide another update to FERC regarding their summer and fall experiences on October 17, 2013.

EPSA and its member companies take the electric-natural gas coordination issues seriously and will continue to be actively engaged in the dialogue at FERC and other venues.

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
RANKING MEMBER

ONE HUNDRED THIRTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE

2125 Rayburn House Office Building
Washington, DC 20515–6115

Majority (202) 225–2927
Minority (202) 225–3641

May 31, 2013

Mr. Paul Cicio
President
Industrial Energy Consumers of America
1155 15th Street, N.W.
Suite 500
Washington, D.C. 20005

Dear Mr. Cicio:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, May 9, 2013, to testify at the hearing entitled "American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape."

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. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions by the close of business on Friday, June 14, 2013. Your responses should be e-mailed to the Legislative Clerk in Word format at Nick.Abraham@mail.house.gov and mailed to Nick Abraham, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, D.C. 20515.

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

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

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

Attachment

Industrial Energy Consumers of America
The Voice of the Industrial Energy Consumers

1155 15th Street, NW, Suite 500 • Washington, D.C. 20005
Telephone 202-223-1420 • Fax 202-530-0659 • www.ieca-us.org

June 14, 2013

The Honorable Ed Whitfield
Chairman
Subcommittee on Energy and Power
2125 Rayburn House Office Building
Washington, DC 20515-6115

Dear Chairman Whitfield:

Thank you for the letter of May 31, 2013 and the questions by Representative Green.

Greater use of cogeneration (CHP) or waste heat recovery (WHR) makes common sense and should be placed among the highest federal energy policy priorities because of its many benefits. CHP can produce power at an energy efficiency rate of 70 percent or better (depending upon conditions) versus conventional power generation at about 32 percent. It reduces energy consumption, reduces air emissions and GHGs, uses less water, increases the reliability of the grid, and importantly, increases the competitiveness of the manufacturing sector. Despite these benefits, regulatory barriers abound and discourage CHP project development.

Financial incentives are the most efficient way to speed the development of distributive energy projects such as cogeneration (CHP) or waste heat recovery (WHR) because they lower the cost of capital. Other words, they improve the rate of return of project. Over two decades ago, Congress provided a 10 percent investment tax credit that resulted in significant new construction of CHP projects that simultaneously increased the competitiveness of the manufacturing sector for years.

Today, the best type of federal incentive is the matching grant approach that requires the company to commit equal amounts of its own capital to the project. Given the austerity of the federal government, industry is not anticipating any type of financial incentive.

However, there is action that the federal government can take that would accelerate CHP projects. There are a large number of regulatory barrier that we believe the Federal Energy Regulatory Commission (FERC) could and should consider. We have listed several of these barriers below, providing an explanation and a potential legislative fix that largely would be directed at FERC. We have also taken the liberty to include barriers to demand response.

INDUSTRIAL ENERGY EFFICIENCY/ CHP/WHR/ DEMAND RESPONSE BARRIERS

POLICY DETAILS

1. Industrial Combined Heat and Power/Waste Heat Recovery (CHP/WHR) – Remove barriers to CHP/WHR investment

a. **Organized Markets** – FERC issues – FERC "deliverability" standards are a barrier to industrial CHP/WHR investments. The standards do not recognize the nature of the industrial CHP/WHR host manufacturer relationship. The standards do not differentiate industrial CHP/WHR from central station power (e.g., merchant power). Potential CHP/WHR facilities are often remote and will routinely consume most of the electricity produced. Transmission upgrades are imposed on industrial CHP/WHR units as if they were sited like a new central station power unit. These standards require that generators prove that their output is deliverable to the grid (load) even if that will not occur; triggering expensive, time consuming studies. The CHP/WHR generator must finance the transmission upgrade upfront. Some Regional Transmission Organization (RTO)s actually requires transmission connections as if the industrial-host load were not present. In addition to FERC interconnection rules, RTO/Independent System Operator (ISO) practices and requirements of short-term capacity payment periods, control of manufacturer CHP/WHR, and discriminatory pricing of CHP/WHR behind the meter, all work against investment in manufacturer CHP/WHR projects. [1]

i. **Streamline network resource service study requirements for deliverability in interconnection.** FERC interconnection rules (deliverability standard) on "Energy Only Service" (EOS) and "Network Resource Service" (NRS) discriminate against manufacturing investment in CHP/WHR. The rules favor sales by more expensive incumbents' with "right" to run. The standard is based on the PJM model of interconnection. Facilities that qualify as a NRS are guaranteed a substantially higher price for electric power than EOS. To get NRS status, facilities must go through an extensive three prong process and pay for transmission upgrades to show power is "deliverable" to load. NRS status allows participation in PJM's auctions to receive a "capacity payment." The standard provides a reduced price paid to EOS providers (which do not qualify as NRS providers). New entrant EOS providers are treated as "marginal units" capable of running simultaneously

[1] http://www.tandfonline.com/eprint/gurpUGCJdnjCtP398tFa/full

without disturbing the NRS incumbents' "right" to run. NRS unit preference exists even if the EOS unit provides power at lower price. This standard unnecessarily limits competition and discourages industrial CHP/WHR investment. Other ISOs (e.g., NY, NE) have adopted a non-discriminatory deliverability standard[2] (as a variation on FERC rules) that is superior and provides any grid-connected unit (that preserves grid reliability, stability and existing transfer capacity) opportunity to compete in both capacity and energy markets. If there is not enough transmission infrastructure to deliver the output from both the new and existing units, then the units are forced to compete on basis of price to determine which unit gets dispatched.[3]

Legislation: FERC shall review generator interconnection standards for industrial CHP/WHR, identify RTO/ISO interconnection (including deliverability standards) practices and processes that unnecessarily limit competition and investment in industrial CHP/WHR, and should consider new rules such as adopting the NY/NE standards.

ii. **Provide longer-term (15 to 20 year) capacity payment periods for industrial CHP/WHR in forward capacity markets.** Industrial CHP/WHR projects with power sales to RTOs are much harder to finance than sales under long-term contracts with utilities at avoided cost under PURPA. This is because power sales agreements with utilities under PURPA would typically establish a capacity payment for about a 20-year term. In RTOs, such as PJM where a separate capacity market exists, sellers can have price certainty for capacity payments on only a 3-year maximum forward basis.

Legislation: FERC shall establish longer-term capacity payments to encourage capital formation for manufacturer CHP/WHR investments e.g., a 15 to 20 year term capacity payment for manufacturer CHP/WHR facilities.

iii. **For non-capacity resources, remove requirements of RTO/ISO control of onsite manufacturer CHP/WHR (energy services).** RTOs and ISOs often require that non-capacity interconnected generators, including onsite CHP/WHR, be under their control, even if the generator is not making sales to the market. This requirement allows an RTO to dispatch a CHP's entire power production capability to other uses based on the needs of the electrical transmission grid, irrespective of the needs of the industrial CHP/WHR's primary business. This requirement is a significant disincentive for any industrial CHP/WHR facility seeking access to the grid. The RTOs and ISOs should not mandate that CHP/WHR facilities comply with all the operational rules developed for merchant

[2] The "Minimum Interconnection Standard," maximizes competitive entry to the grid.

[3] FERC Docket No. RM13-2-000 Small Generator Interconnection Agreements and Procedures, NOPR, January 17, 2013 (http://www.ferc.gov/media/news-releases/2013/2013-1/01-17-13-E-1.asp). This NOPR recites some history of small and large generation interconnection rulemaking.

generators listed in their generic tariff provisions and mandated by execution of their operating agreements. Instead, RTO/ISO tariffs need to be flexible and allow for the refinement of contract terms to accommodate the particular needs and concerns with respect to the curtailment and dispatch of CHP/WHR.

Legislation: For non-capacity resources, the FERC shall prohibit RTO/ISOs from controlling onsite industrial CHP/WHR curtailment and dispatch. The industrial CHP/WHR facility shall have the flexibility to voluntarily commit a portion of its capacity for mandatory control by the RTO/ISO.

iv. **Mandate that behind the meter generation receive Locational Marginal Pricing (LMP) whether as sales to the RTO/ISO or as a demand response mechanism.** Simply stated, the industrial customer (or its demand response provider) should to be allowed to bid its load reduction into the RTO's day ahead or real time market. If the bid is accepted, the customer reduces its load (or turns on its generator) at the designated time, submits a settlement and gets paid LMP at settlement time. No application would be required. Behind the meter generation would be treated as Demand Response (DR). The nodal LMP would apply, nothing special need be done. At one time, NY ISO would not pay a customer for DR if the reduction in grid load was accomplished by running behind-the-meter generation. So, the customer would not be paid. This mandate would prevent this form of discrimination. The policy means that if the customer reduces its takes from the grid by running behind the meter generation, the industrial customer can be paid LMP for the reduction in grid-supplied load. [4]

Legislation: FERC shall order that industrial behind the meter generation shall receive LMP whether as sales to the RTO/ISO or as a demand response mechanism.

b. **States – Public Utility Commission (PUC) Issues** – In markets regulated by States, interconnection requirements also pose barriers to industrial CHP/WHR, but here standardization through high-level guidance may address the issue. For years, guidelines concerning standby, back-up and maintenance power provided under PURPA, have successfully encouraged economic deployment of smaller CHP Qualified Facilities (QF). Larger non-QFs have not had the benefit of such guidelines. Standby back-up and maintenance guidelines should be expanded to larger non-QFs. Some states have enacted discriminatory "exit fees" and "life-of-contract demand ratchets." States have also enacted various Renewable Portfolio Standards (RPS) and Energy Efficiency Resource Standards (EERS) that discriminate against manufacturer Energy Efficiency (EE)/CHP/WHR. Guidance should be provided to States to consider costs and benefits of discrimination against industrial EE, CHP,

[4] http://www.fortnightly.com/fortnightly/2012/08/load-resource

WHR, and DR in any RPS/EERS, exit fees, life-of-contract demand ratchets, and other discriminatory practices.[5]

i. **Standardize interconnection procedures for distribution wires.** Different state requirements are numerous and unnecessarily complicated causing increased cost and process delay.[6]

Legislation: FERC shall study and develop relevant "guidance" on procedures, studies, reasonable hard dead-lines for completion of assessments and associated fees; states would be required to consider adopting these new rules.

ii. **Prohibit discriminatory pricing treatment of "behind the meter" CHP/WHR.** "Behind the meter" generation refers to electricity generated onsite at a facility that is not sold to a RTO or ISO or to another wholesale entity. The RTOs and ISOs have attempted to charge industrial customers who supply their own needs with behind-the-meter generation as if they had taken their entire power supply from the RTO/ISO controlled grid. The attempted charges are for transmission, ancillary services and administrative fees based upon the total electrical consumption of an industrial facility, rather than the "net" amount actually taken from the grid. This cost allocation scheme is known as "gross load" pricing. CHP/WHR projects should not be required to pay for services on a gross load basis, but on the net actually taken off grid.

Legislation: In RTO/ISO markets, FERC shall review and prohibit gross load pricing for CHP/WHR generated electricity on site and not sold to grid or to others.

Legislation: In regulated markets, state authorities should review and prohibit gross load pricing for CHP/WHR generated electricity on site and not sold to grid or to others.

iii. **Adopt firm standby, back-up, and maintenance power fee guidelines for non-QF CHP/WHR facilities that incent CHP/WHR investment.** Guidelines are provided under Public Utility Regulatory Policies Act (PURPA) for the design of just and reasonable utility rates for standby, back-up and maintenance power needed for CHP QF facilities. However, some public utility commissions have interpreted these PURPA provisions differently. Some approved high rates that are barriers for non-QF investment. States should expand QF standby, back-up and maintenance power rules to non-QF facilities. [7]

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[5] http://www.tandfonline.com/eprint/gurpUGCJdnjCtP398tFa/full

[6] FERC Docket No. RM13-2-000 Small Generator Interconnection Agreements and Procedures, NOPR, January 17, 2013 (http://www.ferc.gov/media/news-releases/2013/2013-1/01-17-13-E-1.asp). This NOPR recites some history of small and large generation interconnection rulemakings with the point that these are models for states.

[7] For model standby rates see: http://www.epa.gov/chp/documents/standby_rates.pdf.

Legislation: FERC shall develop guidance for standardization of state rules for standby, back-up and maintenance power fees that fairly represent the cost of providing those services.

iv. **Prohibit "exit fees."** Some states impose exit fees on industrial customers who seek to serve their power requirements from CHP/WHR facilities owned by entities other than themselves (third-party CHP/WHR). The utilities argued that recovering the stranded costs through an exit fee on those who obtain power from such CHP is justified since it protects those customers who remain on the system. Many third-party CHP facilities have not been built because the threat of an exit fee. Federal legislative language should discourage states from supporting practices, tariffs and statutes such as exit fees that are barriers to industrial CHP/WHR.

Legislation: For industrial CHP/WHR facilities, FERC shall develop "guidance" for States to encourage utilities to remove discriminatory tariff provisions such as exit fees.

v. **Remove discriminatory "life of contract demand ratchets."** Some utilities have life of contract demand ratchets in their tariffs for large industrial customers. These serve as a deterrent to increased installation of CHP/WHR since the industrial customer must pay for up to 75% of the demand listed in its contract (for the life of the contract) regardless of whether it takes the power or not. Such laws protect the utility's exclusive franchise, prolong inefficiency in the generation of power, and discriminate against industrial CHP/WHR facilities. Federal legislative language should discourage states from supporting practices, tariffs and statutes such as demand ratchets that are barriers to industrial CHP/WHR.

Legislation: For industrial CHP/WHR facilities, FERC shall study and develop "guidance" for States to encourage utilities to remove discriminatory tariff provisions, such as "life of contract demand ratchets."

vi. **Allow full participation of industrial EE/CHP/WHR in RPSs and EERSs.** To the extent that states have an RPS that has an "energy efficiency" component – states are encouraged to allow CHP, WHR, and industrial EE to participate. Any environmental regulation/legislation should provide extra renewable energy credits (RECs) for electricity generated through CHP, regardless of generation by means of combustion, or the size of the facility. The Energy Efficiency Resources Standard (EERS) portion of any proposal whether it is included in a renewable standard or on a stand-alone basis should allow all of the output of CHP facilities to qualify for energy savings regardless of the amount of the net wholesale sales of electricity generated by the facility. A facility should not be disqualified as a

"CHP system" no matter how much electricity it sells, and all its electricity should be eligible for the CHP savings calculation. [8]

Legislation: FERC should study and issue guidance to States to consider costs and benefits of full participation of manufacturer EE, CHP, WHR, DR in any RPS/EERS.

vii. **Remove CHP/WHR facility barriers to sales of electricity or steam and crossing public right of way.** Some states do not allow a manufacturer or third-party CHP/WHR facility to provide electrical or thermal services by crossing streets and public right of ways. Manufacturer and third-party owned facilities may not be allowed to sell electricity and/or steam to affiliated and unaffiliated adjacent facilities whether or not streets or public right of ways must be crossed. Industrial and third-party owners of CHP/WHR generally do not have powers of eminent domain for electric service and thermal pipelines, whether served facilities are adjacent, nonadjacent, affiliated or unaffiliated.

Legislation: State authorities should allow industrial or third-party CHP/WHR facilities to provide electrical or thermal services or both, by crossing streets and public right of ways. States should consider grants of limited powers of eminent domain for owners or operators of CHP/WHR facilities to provide electricity and thermal services.

2. Industrial Electricity EE/DR – Remove regulatory barriers to industrial energy efficiency and demand response

a. **Develop baseline Measurement and Verification (M&V) standards for Highly Variable and other industrial Loads (HVLs).**[9] Energy markets are amenable to the adoption of more consistent M&V approaches than capacity markets. FERC Order 745 has forced all of the jurisdictional wholesale markets to address common issues associated with demand response participation in wholesale energy markets. Despite the fact that each ISO/RTO has concluded that energy should be measured somewhat differently, the similarities in measurement approaches for energy are far greater than for capacity.

Common approaches in all markets exist. Yet, DR providers (industrials or their aggregators), are forced to adapt to the multiple market idiosyncrasies with complex and expensive transaction systems. The maintenance of the plethora of current DR market management preferences thwarts cost-effective operation of industrial facilities.

[8] http://www.epa.gov/chp/documents/ps_paper.pdf
[9] FERC Docket No. RM05-5-020 Standards for Business Practices and Communication Protocols for Public Utilities (2012)

Each ISO/RTO has developed common, but slightly different, energy M&V rules. Manufacturers do not see how any one of these could be materially harmful to any market. The benefits of a common DR M&V rule for energy across markets would outweigh the costs.

Among the common and pragmatic DR M&V "best practices" widely adopted are the following: baseline in-day adjustment for accuracy of M&V; baseline adjustment for planned dispatch; baseline adjustment for event or economic offer days; and a mechanism to prevent stale baselines. And all markets claim accuracy approaches on which all transactions depend.

However, for industrial HVLs there is no common approach for baseline determinations. Though more suitable for commercial load purposes, none of the five existing North American Energy Standards Board (NAESB) baseline performance evaluation methods are suited to a large proportion of industrial HVLs. Industrial HVLs tend to have business-as-usual schedules that are more responsive to the forces of market conditions, rather than more predictable institutional, weather, or seasonal demand of the commercial customer. For many industrials, production and maintenance schedules change and historical meter data become irrelevant to business-as-usual consumption.

Legislation: FERC shall develop standardized DR M&V baselines in energy markets in RTOs/ISOs. Additionally, FERC should have a strategy to move organized markets toward responsive and responsible development of industrial HVL, DR M&V standards. Congressional oversight should encourage the FERC to move more expeditiously on standardization of M&V baselines for energy DR, including industrial HVLs.

b. Assure organized markets give parity to DR and generation in forward capacity markets. Further development of substantive M&V standards broadly applicable to RTOs and ISOs is needed. The status quo is unjust, unreasonable or unduly discriminatory. The lack of common DR M&V standards creates a market barrier of high magnitude and a lost opportunity for increased industrial energy efficiency, reduced emissions and avoided construction of new power generation facilities.

Generation is measured under common protocols and equipment everywhere in the world including the U.S.; demand response is not. There is little or no reason to support the status quo of balkanized market rules in DR M&V. By law, the FERC has embarked on a path to bring generation and demand response to comparable competitive treatment in wholesale markets. However, the slow pace of implementation of the law of DR M&V standards is unacceptable.

Legislation: FERC shall establish parity for industrial DR and generation in forward capacity markets in RTOs/ISOs. Seek congressional oversight and necessary legislation to encourage the FERC to move expeditiously on parity for capacity DR.

c. **Broaden industrial EE/DR product participation (energy, capacity, reserves, and regulation) in organized markets.** Manufacturers recognize the need for a standard approach to Energy Efficiency Measurement and Verification ("EE M&V"). Manufacturers support the efforts of the NAESB and FERC (though slow) in this area because of the growing importance of EE in organized markets. EE will be increasingly called upon because both industrial site and end-use EE are frequently identified as a low-cost solution to achieving emissions reductions in the utility sector. All forms of EE are increasingly important in making up for coal-fired base-load generation retirements caused by increasingly stringent US EPA regulations or by declining natural gas prices.

   EE/DR M&V should be sufficiently rigorous to achieve an appropriate level of accuracy and not require expensive features that contribute only to unneeded precision. Also, in order for EE/DR to make maximum contributions to emissions reductions and "generation," all FERC-approved M&V methods must be transparent.

   Currently, RTO processes are overly prescriptive, resulting in M&V costs that exceed the potential benefit of industrial participation in an EE project. Those processes seem designed to achieve a high level of precision not really needed to accurately quantify energy savings. Many small projects simply are rendered too costly.[10]

   With barrier removal, the number of viable projects would increase dramatically. More projects mean more competition in capacity markets. More manufacturing EE projects results in a more competitive industrial sector along with job creation and exports.

Legislation: FERC shall initiate a strategy to expeditiously develop streamlined, cost-effective application of coincidence factors for simple conversion of energy use to peak demand reduction. FERC should encourage RTOs to accept industry developed coincidence factors when evaluating EE M&V plans. Congressional oversight and authorization should encourage FERC to move expeditiously on development and

[10] This problem begins with the International Performance Measurement, and Verification Protocol (IPMVP) standards which are designed for determination of reduction in energy use. IPMVP standards are not designed for determination of reduction in peak demand (i.e. capacity). The results of EE M&V determinations compliant with IPMVP and NAESB standards undertaken and applied to *energy use* for contractual purposes, are not applicable to *peak reduction* determinations. For peak reduction determinations, the EE M&V determinations must be repeated with consideration of the different goals – *at substantial cost.* One simple remedy is use of coincidence factors to convert energy use reduction to peak demand reduction. The standards allow for application of coincidence factors. *But RTOs subject the coincidence factors to extensive validation for each project despite availability of industry demonstrated values for a range of project types and conditions.* RTO acceptance of industry developed coincidence factors would remove a substantial barrier to market access by many manufacturers to provide EE for capacity purposes

application of coincidence factors for conversion of energy use to peak demand reduction.

We are grateful for Representative Green's and your interest in this subject and look forward to future discussions.

Sincerely,

Paul N. Cicio
President

Cc: The Honorable Bobby Rush, Ranking Member

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 1,500 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemical, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, brewing, and cement.

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ONE HUNDRED THIRTEENTH CONGRESS

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June 3, 2013

Mr. Robert Gramlich
Interim CEO
American Wind Energy Association
1501 M Street, N.W.
Suite 1000
Washington, D.C. 20005

Dear Mr. Gramlich:

Thank you for appearing before the Subcommittee on Energy and Power on Thursday, May 9, 2013, to testify at the hearing entitled "American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape."

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. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions by the close of business on Monday, June 17, 2013. Your responses should be e-mailed to the Legislative Clerk in Word format at Nick.Abraham@mail.house.gov and mailed to Nick Abraham, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, D.C. 20515.

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

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

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

Attachment

Questions submitted by The Honorable Mike Pompeo

1. During an appearance on Fox Business last year, in response to charges that subsidized wind was undermining the economic viability of coal and nuclear power plants, then AWEA head Denise Bode described nuclear and coal as inflexible resources because they have to run all the time. She said that gas and wind were, in contrast, flexible resources because they don't have to run all the time. However, as the testimony from this hearing bears out, wind doesn't run all the time because it can't. It's an intermittent resource that only produces power when the wind blows and consumers pay the price of those reliability costs. Given that fact, if wind continues to contribute to coal and nuclear retirements, our cheapest baseload power sources that threatens reliability and increases costs, should we continue to subsidize wind with the production tax credit (PTC) and, if so, for how long?

Wind energy reduces electricity costs for consumers and makes the power system more reliable. As I explained in my testimony, all energy sources require backup from other energy sources on the grid, and in fact the cost of reliably integrating wind energy onto the grid is lower than the cost of accommodating the unexpected failures of large conventional power plants. Specifically, data from the Texas grid operator indicate that the cost of integrating more than 10,000 MW of wind energy amounts to about six cents on the typical Texas household electric bill, while other data indicate that the cost of maintaining enough reserves to reliably accommodate the unpredictable failures of large conventional power plants is forty times higher at around $2.50 per monthly electric bill.[1] The Texas cold snap of February 2011, when dozens of conventional power plants unexpectedly broke down while wind energy earned accolades from the grid operator for continuing to produce as expected,[2] is a clear illustration that a diverse energy mix that includes greater use of wind energy makes the power system more reliable and better for consumers.

The consensus of utilities and other industry experts is that low electricity demand, low natural gas prices, and environmental regulations are the primary factors responsible for coal and nuclear plant retirements.[3] In contrast, the wind energy production tax credit (PTC) has virtually zero impact on the economics of other generators. The only time the PTC is reflected in electricity market prices is when wind energy is setting the market price, and that almost never happens.[4] Moreover, when it does, the effects are typically limited to very small, isolated segments of the grid where there are few generators other than wind energy.

Through means that are entirely unrelated to the PTC, wind energy does drive consumers' electricity prices down by displacing output from more expensive power plants, which are almost always the least efficient fossil-fired power plants. This massive benefit for consumers and the environment is why the public overwhelmingly supports greater use of wind energy, and we are not apologetic about displacing higher-cost sources of energy. In addition, zero fuel cost wind energy protects consumers from fluctuations in the price of other fuels, much like a fixed rate

[1] http://docs.house.gov/meetings/IF/IF03/20130509/100816/HHRG-113-IF03-Wstate-GramlichR-20130509.pdf, at footnotes 6 and 7
[2] http://www.texastribune.org/2011/02/04/an-interview-with-the-ceo-of-the-texas-grid/
[3] http://www.brattle.com/_documents/UploadLibrary/Upload1082.pdf
[4] http://www.greentechmedia.com/articles/read/Wind-And-The-Myth-of-Widespread-Negative-Pricing

mortgage protects homeowners from variations in interest rates. Last month, Synapse Energy Economics completed a report that found that doubling wind energy use beyond current standards in PJM would save consumers $6.9 billion on net every year by displacing higher-cost sources of energy.[5] It is important not to conflate this large and widespread benefit of wind energy, which is due to wind's zero fuel cost and occurs regardless of whether a wind project is receiving the production tax credit, with the exceedingly rare and localized instances when wind energy is setting the market clearing price.

With longer-term policies that provide certainty for businesses, such as the PTC, the wind industry will become cost-competitive with all other energy technologies. As you know, other traditional energy technologies have benefited from tax incentives and other policy support for decades. As the cost of wind energy continues to decrease, assuming all incentives and other federal policy support are removed for other technologies, there will be a point in time when federal incentives would no longer be necessary for the wind industry.

2. Public Utility Commission of Texas Chair Donna Nelson stated that "Federal incentives for renewable energy . . . have distorted the competitive wholesale market in ERCOT. Wind has been supported by a federal production tax credit that provides $22 per MWH of energy generated by a wind resource. With this substantial incentive, wind resources can actually bid negative prices into the market and still make a profit. We've seen a number of days with a negative clearing price in the west zone of ERCOT where most of the wind resources are installed . . . The market distortions caused by renewable energy incentives are one of the primary causes I believe of our current resource adequacy issue . . . [T]his distortion makes it difficult for other generation types to recover their cost and discourages investment in new generation." Do you believe her statement is accurate? If not, please explain. Do you recognize that negative pricing is contributing to resource adequacy challenges in Texas?

Negative pricing is not contributing to resource adequacy challenges in Texas or elsewhere. Market data from the Texas grid operator, ERCOT, indicate that negative electricity prices are exceedingly rare in Texas. Negative prices accounted for less than 1% of day-ahead market price points and around 2% of real-time market price points in ERCOT in 2011, based on a sample of over 1 billion real-time market price points and almost 5 million day ahead price points in the ERCOT market analyzed by Ventyx, a company that compiles and analyzes electricity market data.[6] Moreover, other energy sources, such as nuclear, account for some share of these negative prices.

Even though Texas added 1,825 MW of wind capacity in 2012, an increase of almost 18%, instances of negative prices were down more than 60% for the first part of this year relative to the same time period last year.[7] That is because negative prices are caused by a lack of

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[5] http://cleanenergytransmission.org/uploads/EFC%20PJM%20Final%20Report%20May%209%202013.pdf

[6] Ventyx analysis for AWEA

[7] Comparison of frequency of negative prices at load zones for January-March 2013 versus January-March 2012, based on ERCOT data available at http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13061&reportTitle=Historical%20RTM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey

transmission capacity preventing low cost energy sources, such as wind, from reaching consumers. As Texas has increased the transmission capacity to move low-cost wind energy from the western part of the state to consumers in other parts of the state, the already extremely low frequency of negative prices has fallen even further. This trend is further confirmed by ERCOT data indicating that the amount of wind generation curtailment, which closely tracks the occurrence of negative prices in West Texas, has fallen from 8.5% of potential wind generation in 2011 to 1.7% for the last five months of 2012.[8] Instances of negative prices should fall to near zero by the end of 2013 when the Competitive Renewable Energy Zone transmission lines are completed, and the same should occur in other regions as they complete long-needed upgrades to their grids.

Regardless, there has been no impact on resource adequacy because these rare instances of negative prices have been almost entirely confined to the West Zone of ERCOT. The West Zone of ERCOT only accounts for around 5% of the total conventional generating capacity of ERCOT, and a similar share of ERCOT's electricity demand. As a result, in the zones of ERCOT that account for around 95% of its electricity demand, negative prices should not have had any impact on investors' decisions regarding whether to build new power plants.

3. The North American Electric Reliability Corporation (NERC), overseen by the Federal Energy Regulatory Commission, is a not-for-profit organization charged by the Federal Power Act, as amended by the Energy Policy Act of 2005, with ensuring the reliability of the bulk power system in North America. In its 2012 Long-Term Reliability Assessment, NERC found that "[o]perationally, an increase in wind resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas, where large concentrations of wind resources have been added, system planners must accommodate added variability by increasing the amount of available regulating reserves, and potentially carrying additional operating reserves." Do you agree with this statement? If not, please explain.

I am unable to find that statement in the 2012 Long-Term Reliability Assessment, and a thorough word search indicates that the statement does not appear in the document. However, the document does include this discussion of wind integration:

"ERCOT has significant experience maintaining operational reliability with significant and increasing levels of interconnected variable generation. Using a combination of state-of-the-art wind generation forecasts and flexible levels of ancillary services, ERCOT will effectively manage available wind and solar generation to support system reliability utilizing current procedures."[9]

Similarly, in NERC's State of Reliability 2013 report, a 75-page report examining threats to grid reliability over the last year, the only mention of wind energy is one paragraph explaining that wind energy is being reliably integrated:

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[8] 2011 ERCOT data from Wiser, R., Bolinger, M., *2011 Wind Technologies Market Report*, August 2012. Page 43. Available at http://eetd.lbl.gov/ea/emp/reports/lbnl-5559e.pdf ; 2012 data provided by Bolinger, M., Lawrence Berkeley National Laboratory, to appear in 2012 *Wind Technologies Market Report*

[9] http://www.nerc.com/files/2012_LTRA_FINAL.pdf, page 83

"There were no significant reliability challenges reported in the 2011/2012 winter and the 2012 summer periods resulting from the integration of variable generation resources. More improved wind forecast tools and wind monitoring displays are being used to help system operators manage integration of wind resources into real-time operations."[10]

Returning to the statement that you quoted, I agree that the second sentence is correct. As I explained in my testimony, adding large amounts of wind energy to the grid can incrementally increase the need for the flexible reserves that grid operators have always used to accommodate fluctuations in electricity demand and unpredictable failures at conventional power plants.

However, the first sentence seems to be contradicted by NERC's finding in its State of Reliability 2013 that "There were no significant reliability challenges reported in the 2011/2012 winter and the 2012 summer periods resulting from the integration of variable generation resources."[11] The data I cited in my testimony document that variations in electricity demand and failures at conventional power plants are far larger contributors to total power system variability. Grid operators already had many of the tools needed to accommodate wind energy because, as NERC's 2012 Long-Term Reliability Assessment explains in its discussion of wind integration, "Power system planners are already familiar with designing a system that can be operated reliably while accommodating a certain amount of variability and uncertainty, particularly as it relates to system demand and, to a lesser extent, to conventional generation."[12] While some grid operating tools may need to be updated to accommodate very high levels of wind energy, NERC, utilities, and other groups have been pro-actively working on those solutions for years.[13]

As a result, grid operators that use efficient operating practices, like the Midcontinent ISO (MISO) and ERCOT, have been able to reliably integrate more than 10,000 MW of wind with minimal increases in the need for reserves. MISO has explained that the impact of more than 10,000 MW of wind generation on its reserve needs has been "little to none,"[14] while the small impact of wind on ERCOT's reserve needs was discussed in my testimony.

4. Given the concerns raised regarding the costs of integrating renewables, should the wind sector pay the full costs of integrating those resources? Should electricity customers not served by wind integrated into the grid pay for such integration through the socialization of transmission costs?

Currently, wind generators can be assigned integration costs, while conventional generators are not allocated their integration costs. Some utilities currently charge wind generators for reserve services,[15] and the Federal Energy Regulatory Commission (FERC) has issued an Order that establishes the process for other utilities to impose such a charge.[16] In contrast, I am not aware of

[10] http://www.nerc.com/files/2013_SOR.pdf, page 47
[11] *Ibid.*
[12] http://www.nerc.com/files/2012_LTRA_FINAL.pdf, page 32
[13] http://www.nerc.com/files/IVGTF_Report_041609.pdf
[14] http://www.uwig.org/san_diego2012/Navid-Reserve_Calculation.pdf
[15] http://eetd.lbl.gov/ea/emp/reports/lbnl-5559e.pdf, page 67
[16] http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf

any utility in the United States that charges large conventional generators for the full cost of maintaining the expensive, fast-acting contingency reserves that must be held 24/7 in case a large generator unexpectedly goes offline. Instead, these conventional generation integration costs are typically broadly socialized across all transmission customers.[17]

Because wind generators can be forced to pay their small integration costs while conventional generators do not pay their much larger integration costs, the electricity market playing field is currently slanted against wind energy. In light of that fact, AWEA has consistently argued at FERC and elsewhere that wind energy should be treated the same as other resources in the allocation of integration costs.[18]

In response to your question about transmission costs, to be approved by FERC, transmission cost allocation policies must be consistent with the principle of cost causation that those who benefit from transmission pay for it.[19] Texas was one of the first areas to recognize that transmission costs should be broadly allocated because transmission broadly benefits ratepayers across the state by helping to ensure that electricity markets are open and competitive, giving consumers access to lower cost energy, making the power system more reliable, and providing other benefits. Other regions, such as MISO[20] and the Southwest Power Pool,[21] have followed Texas's example. Because it has been demonstrated that high-voltage transmission greatly benefits customers broadly distributed across the regions served by it,[22] AWEA has consistently supported policies that broadly allocate the costs of transmission to those who benefit.

[17] http://www.nrel.gov/docs/fy11osti/51860.pdf, pages 11-16
[18] http://www.calwea.org/pdfs/publicFilings2010/AWEA_et_al_comments_FERC_VER_NOPR.pdf
[19] http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf
[20] http://www.ferc.gov/whats-new/comm-meet/2010/121610/E-1.pdf
[21] http://www.ferc.gov/whats-new/comm-meet/2010/061710/E-7.pdf
[22] http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/BC/Energy_and_Environment/files/Southwest%20Power%20Pool%20Extra-High-Voltage%20Transmission%20Study.pdf

BEFORE THE HOUSE SUBCOMMITTEE ON ENERGY AND POWER

"American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape"

Responses to Additional Questions Posed to Dr. Jonathan A. Lesser, President, Continental Economics, Inc., subsequent to the May 9, 2013 Hearing.

Questions from the Honorable Edward J. Markey

1. **In testimony before the Committee, you spoke of "The potential loss of thousands of megawatts of intermittent generation in a short time, which has occurred in the past."**

   a. **Have modern weather forecasting and grid planning and dispatch tools allowed grid operators to better anticipate and respond to changes in output from intermittent renewable generators?**

   b. **How much warning do grid operators typically have today regarding these types of changes in output and how does this compare with the amount of warning time operators have to deal with forced outages from conventional nuclear and fossil generators?**

Response

(a) It is unclear what "modern" weather forecasting and grid planning and dispatch tools are being compared with (e.g., the complete absence of such tools or something else). The answer depends on the nature of the intermittency. For example, a passing cloud can obscure the sun over a photovoltaic array, causing an almost instantaneous drop in generating output. To my knowledge, there are no forecasting tools that can predict such an event, other than direct observation several minutes before the event. Forecasters clearly can predict incoming storm fronts, etc., with some degree of accuracy beforehand, and thus have some ability to predict the output of intermittent renewable resources to a degree. As I stated in my written testimony, according to at least one peer reviewed study published by Forbes, et al., (2012), forecast and operational data in areas including Texas, as well as in European countries, do not support such forecast accuracy claims.[1] In other words, forecasting intermittent resource availability is not especially accurate. Intermittent generators are far more likely to fail to comply with their day-ahead forecast

[1] M. Delucchi and M. Jacobson, "Providing All Global Energy with Wind, Water, and Solar Power, Part II: Reliability, System and Transmission Costs and Policies," *Energy Policy* 39 (2011), pp. 1170-1190.

availability than traditional schedulable resources. This adds to the costs of integrating intermittent resources because inaccurate short-term forecasts of intermittent generation increase the overall cost of meeting electric demand.

(b) This question suggests an "apples to oranges" comparison that fails to recognize that wind generators can also experience sudden forced outages due to equipment failure. For a wind generator, a forced outage does not occur because the wind stops blowing. The definition of a forced outage is one that is unexpected. Therefore, operators typically do not have a "warning" for forced outages.

Prepared by: Jonathan A. Lesser

2. **Two nuclear plants in Illinois have shut down abruptly in recent weeks, one with a capacity of over 2,200 MW and another with over 1,000 MW of capacity.**

   a. **What level of fast-acting reserves must be held in reserve around the clock, 365 days a year to ensure system reliability when large conventional power plants suddenly go completely offline in this manner?**

   b. **Do rate payers typically pay for these reserves?**

Response

(a) I am unclear as to what the term "fast-acting" reserves is intended to mean, but, for the purposes of this response I will assume that it refers to spinning and non-spinning reserves. Although frequency reserves, also known as automatic generation control (AGC), are the "fastest" type of reserve, in that AGC responds instantly to changing frequency and voltage caused by the constant fluctuations in supply and demand, it is not specifically designed to compensate for forced generator outages.

In addition, the reserve requirement is not solely a function of a particular contingency (in this case, the referenced shutdown of nuclear power plants). Rather, reserve requirements depend on an overall analysis of the system and its ability to meet the 1-in-10 year loss-of-load-expectation (LOLE) reliability standard. The impacts of a single contingency (N-1 event) on reliability and the need for spinning and non-spinning reserves depends on the location of the contingency (i.e., whether it occurs in a transmission constrained region requiring local generating resources), and the size of the overall transmission system in which the generating units operate. It is important to distinguish the forced outages sometimes experienced by conventional power plants from the general lack of availability associated with intermittent energy resources like wind and solar. For example, forced outages result in the unavailability of power production and occur very rarely during the course of a given calendar year. By contrast, my research has shown that intermittent wind resources are only available around 30% of the time during the year (thus unavailable about70% of the time). This is much higher than the typical forced outage rates for schedulable (predictable) resources, which typically have forced outage rates of 2-5% per year.

(b) Ratepayers ultimately pay for energy, capacity, reserves, and other ancillary services through the rates they pay. This is why it is so important to understand that the costs associated with integrating intermittent resources are substantially higher than those associated with doing so for conventional baseload resources for the reasons set out in my testimony.

Prepared by: Jonathan A. Lesser

3. **Utilities can and do charge wind plants for integration costs. Do utilities typically charge the owners of conventional power plants for the integration costs associated with their forced outages?**

   a. **Do you believe they should?**

   b. **Why or why not?**

Response

(a) It is important at the outset to note that "integration costs," which deal with interconnecting a power source to the grid, do not apply to forced outages, which occur when an event, oftentimes external, may cause a conventional power plant to go offline. Furthermore, it must be noted that interconnection at transmission and distribution voltage levels are quite different.

I shall attempt to provide a general response discussing the case of a forced outage and then the more general issue of integration costs. To do so, assume a power plant is independently owned (i.e., not owned by the utility). We can consider the following two cases.

Case 1: assume the power plant owner has signed a firm power purchase contract with the utility, i.e., a contract that promises the power plant will deliver to the utility a specified amount of energy per hour. For ease of exposition, assume delivery is for a fixed amount in all hours. If a power plant owner suffers a forced outage, it would only pay the utility "damages" associated with the value of the undelivered generation, or would be required to provide an equivalent quantity of power. For example, if the contract was for 100 MW and the forced outage caused the power plant owner to be unable to deliver power for 24 hours, then the damages would be 100 MW x 24 hours = 2,400 megawatt-hours. If the market price of power during the outage was $50/MWh, the power plant owner would be required to compensate the utility in the amount of 2,400 MWh x $50/MWh = $120,000.

Case 2: assume the power plant owner sells energy into the wholesale power grid, e.g., the power plant owners sells all power into the PJM day-ahead and real-time energy markets. If, in the PJM day-ahead market, the owner schedules 2,400 MWh of electricity, but because of a forced outage, cannot deliver that power, then the power plant owner will be assessed a penalty by PJM. In addition, the outage will affect the power plant's equivalent forced outage rate – demand (EFORd), which will reduce its future capacity payments by reducing its calculated unforced capacity (UCAP) level. The power plant owner further loses all energy sales revenues in PJM for those hours.

Next, we can consider the more general issue of integration costs. Integration costs include the direct costs of interconnecting a generator to the power grid, whether at the transmission or distribution voltage levels, such as the cost of a substation needed to step up ("transform") the voltage output of the power plant (regardless of type) to the correct interconnection voltage. Integration costs also include indirect costs associated with ensuring interconnection of a specific power plant does not lead to reliability violations.[2] In other words, integration costs are those associated with "managing the delivery of energy."[3]

Typically, all commercial generation plant owners must pay the direct costs associated with interconnecting their power plants to the transmission or distribution system grid. In a RTO like PJM, transmission level integration costs are paid to PJM, and not an individual utility. Moreover, many of these costs are socialized across the grid, consistent with FERC policy. For costs that are not socialized, i.e., paid for by the transmission-owning utility, such utilities typically charge all power suppliers for those costs. These charges must be approved by the appropriate regulators. At the bulk transmission system level, they must be approved by FERC. At the distribution system level, they are approved by the appropriate state utility regulators.

Prepared by: Jonathan A. Lesser

2 A power plant can have multiple individual generating units. For example, a wind power plant might consist of several hundred individual turbines.

3 NREL, "Eastern Wind Integration Study, February 2011, p. 31.

4. **On the PJM system, how do the changes in wind output over the course of an hour typically compare to the magnitude of changes in electricity demand over the course of an hour? Could you provide me with data that would allow me to compare these changes for an hour long period that occurs during:**

   a. **a typical spring or fall day**

   b. **a winter night**

   c. **a summer day**

Response

The change in demand from hour-to-hour in PJM depends on the time of day, not just the season. For example, the change in total electric demand between 3AM and 4AM is generally small. Based on data between January 1, 2009 and August 31, 2012, for example, the average change in demand between these hours was 1.06% (in absolute value). The average change in demand between the hours of 6AM and 7AM was 7.22%. The largest hour-to-hour change in demand over the entire 44-month period was 24.6%.

In contrast, the average hourly change in wind production between 3AM and 4AM was10.57%. On November 6, 2011, wind output decreased by 3,106 MW, or 49.95%, between the hours of 1PM and 2PM. Conversely, load decreased by 2.19% over that same time period.

I believe the conclusion from these data is obvious: the magnitude of wind generation variability is far greater on an hourly basis than the magnitude of load variability.

Prepared by: Jonathan A. Lesser

5. **You testified at the hearing that "There is a small impact on emissions because of renewables, but it is very small because you have to operate the remaining parts of the power grid more inefficiently by cycling conventional plants up and down ... it's less efficient, therefore there are more emissions."**

   a. **Are there any peer-reviewed studies that support this claim?**

   b. **The National Renewable Energy Laboratory (NREL) examined data from continuous emission monitors at nearly every fossil-fired power plant in the Western U.S. and found that renewable energy produces the expected emissions reductions and has no negative impact on the efficiency of other power plants. Do you disagree with NREL's conclusions? If so, please submit data and analysis to substantiate these views.**

<u>Response</u>

a) In my testimony, I was referencing a detailed study prepared by Bentek Energy, a highly respected provider of energy data and analysis. I do not know if the authors of that study have published their results in any peer-reviewed energy journals. In addition to the Bentek Energy study referenced in my testimony you can review the following peer-reviewed paper on the same subject matter. *See* Daniel Kaffine, Brannin McBee and Jozef Lieskovsky. 'Emissions savings from wind power generation in Texas.' *The Energy Journal*, 34(1): 155-175, 2013. Working paper version with MISO and CAISO at http://econbus.mines.edu/working-papers/wp201203.pdf. The study finds that "increasing wind penetration will likely require an increase in ramping of thermal generation, as the magnitude of shifts in wind speed is amplified into larger swings in aggregate wind generation. This increased cycling of thermal generation (in magnitude and potentially frequency) may erode the emissions savings per MWh of wind power as thermal generation is utilized less efficiently to accommodate wind." Importantly, the study concludes that the environmental benefits from emissions reductions in ERCOT fail to cover government subsidies for wind generation.

b) There is no reference to a specific NREL study, which makes it difficult for me to respond. Nor is it clear what is meant by "efficiency," although the typical measure of fossil-fuel power plant efficiency is the "heat rate," measured in Btus of fossil fuel input per kWh of generation. Moreover, because the western power system, especially the Pacific Northwest, contains significant quantities of hydroelectric power, the impacts of wind on emissions should be expected to be different than in the eastern power system, which is more heavily fossil-based.

   However, assuming the question refers to the paper by D. Lew, et al., "Impacts of Wind and Solar on Fossil-Fueled Generators," NREL Report No. CP-5500-53504, August 2012, which is the only NREL report I am aware of on the particular topic cited, there may be some confusion as to what the authors' analyzed. Specifically, the authors of this study used EPA emissions data from 2008 and applied it to the hypothetical conditions posited in NREL's Western Wind and Solar Integration Study (WWSIS). The WWSIS is a hypothetical analysis of power system operations under high wind penetration levels. Thus, Lew, et al., did not evaluate the actual operating efficiency of Western Systems Coordinating Counsel fossil-fuel plants in 2008. They used a production-simulation model and actual emissions data to predict how fossil-fuel generation operating costs and emissions levels would change under the high wind penetration levels assumed in the WWSIS. As the authors state on page 7 of that paper: "This is not a specific projection for the Western Electricity Coordinating Council. It is an example of how cycling might impact the emissions benefits of wind in a generic system with hourly generation based on the WWSIS results."

Finally, and contrary to the premise of the question, Lew, et al., concluded that cycling and startups reduced emissions benefits of wind, i.e., increased emissions and operating costs of western system fossil fuel plants in their simulation.

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