S. HRG. 111–44

NET METERING

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY

OF THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

ONE HUNDRED ELEVENTH CONGRESS

FIRST SESSION

TO

RECEIVE TESTIMONY ON NET METERING, INTERCONNECTION STANDARDS, AND OTHER POLICIES THAT PROMOTE THE DEPLOYMENT OF DISTRIBUTED GENERATION TO IMPROVE GRID RELIABILITY, INCREASE CLEAN ENERGY DEPLOYMENT, ENABLE CONSUMER CHOICE, AND DIVERSIFY OUR NATION'S ENERGY SUPPLY

MAY 7, 2009

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NET METERING

THURSDAY, MAY 7, 2009

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

The subcommittee met, pursuant to notice, at 2:36 p.m., in room SD–366, Dirksen Senate Office Building, Hon. Maria Cantwell presiding.

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

Senator CANTWELL. This hearing will come to order.

Today's hearing is to discuss a wide range of policies critical to transitioning our Nation to a cleaner, more diverse, and more distributed 21st century energy system.

While most of the discussion in this committee recently has focused on siting of high voltage transmission lines, a number of members of this committee, including myself and Chairman Bingaman, are developing legislative proposals intended to address longstanding barriers that are inhibiting rate payers in the Nation from reaping the benefits of distributed generation technologies.

In particular, at today's hearing we will focus on national net metering and interconnection standards, measures to address peak demand, the state of distributed generation technology, and the need to infuse intelligence into the Nation's electricity grid to increase efficiency, reliability, and to allow for a more accurate price signal.

As we will hear from today's witnesses, distributed generation can allow for a wide range of untapped resources to come online and to meet our Nation's growing energy demands and reduce our carbon footprint. With the right policies in place, homes and businesses across the country will be able to own electricity from solar panels on their roofs or maybe even hook up a generator in a nearby stream or farms will be able to use their animal waste to produce electricity, turning a disposal headache into a new source of income.

The paper and wood products industries will be able to use their leftover woody biomass to create new sources of carbon-neutral electricity.

Manufacturing industries will be able to invest in a combined heat and power technology generation electricity from process heat that otherwise is just released into the atmosphere.

Communities will be able to keep more revenue and jobs locally, and homeowners will be empowered to generate their own electricity.

So the question before us is, if there are so many direct and indirect benefits from distributed generation, why is so little coming online relative to the potential and national need?

While a number of States are pushing the envelope, the resulting patchwork of regulations and standards has stifled development and slowed what would be a robust source of interstate commerce.

So there may be a role for well thought-out Federal legislation which is mindful of the historic jurisdictions of State regulatory commissions, but still provides the certainty, incentives, and guidance we need to make distributed generation a reality.

I appreciate that this is a very tricky balance. One of the first pieces of legislation I introduced, coming into the Senate in 2001, was a national net metering and interconnection standard. But as we tried for several years to push that bill forward, we continually ran into opposition from stakeholders who benefited from the status quo. Hopefully now with a greater appreciation of distributed generation and the urgent need to bring clean energy alternatives online, we will be able to incorporate the policies we need in the comprehensive energy bill that the committee is working on.

I know that my colleague, the chairman of the full committee, is here, and I wondered if he wanted to make any opening statements.

STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

The CHAIRMAN. Thank you very much for chairing this hearing and thanks to all the witnesses for being here.

This is an issue that I think is very important for us to try to come to grips with. We thought in the 2005 energy bill that we had dealt with this to a significant extent, but obviously, I think history has demonstrated that we did not do all that needed to be done. So I think this hearing should be enlightening and help us to understand what additional steps we can take to facilitate energy production from all sources, including a lot of these small technology sources that are becoming more and more capable and cost-effective.

So thank you again for having the hearing.

Senator CANTWELL. Thank you, Senator Bingaman.

Now the Energy Subcommittee of the full Energy and Natural Resources Committee will hear from our witnesses. We are joined today by Kevin Kelly, who is the Director of the Division of Policy Development within the Federal Energy Regulatory Commission. Thank you for being here today.

Garry Brown, Chairman of the New York State Public Service Commission. Thank you, Mr. Brown, or being here.

Mr. Chris Cook, Managing Director and Co-Founder of Sunworks from Dunn Loring, Virginia. Thank you for being here.

David Weiss, President and COO of the Energy Services Division for Pepco Energy Services. You may have had to travel the least to be here, but thank you anyway for being here.

Irene Kowalczyk—thank you very much for being here—is the Director of Energy Policy and Supply from MeadWestvaco Company from Glen Allen, Virginia.

So thank you all for being here, and we will start with you, Mr. Kelly. If you could, we certainly will take longer statements from the witnesses, but if you can keep it to 5 minutes, that would be great and that will allow members an opportunity to ask questions.

Mr. Kelly.

STATEMENT OF KEVIN A. KELLY, DIRECTOR, DIVISION OF POLICY DEVELOPMENT, OFFICE OF ENERGY POLICY AND INNOVATION, FEDERAL ENERGY REGULATORY COMMISSION

Mr. KELLY. Yes. Good afternoon, Madam Chairman, Senator Bingaman. Thank you for the opportunity to speak here today.

My name is Kevin Kelly. I am the Director of the Division of Policy Development in FERC's newly minted Office of Energy Policy and Innovation. It just started this week. I appear before you today as a staff witness, and my testimony is not necessarily the views of the commission or any individual commissioner.

I will describe the commission's rules for interconnecting small generators and its few precedents regarding net metering and distributed generation.

Obviously, a generator must interconnect to a utility's transmission or distribution system in order to make its energy available to customers. The commission regulates certain generator interconnections under the Federal Power Act. It has established standard interconnection procedures for both large and small generators.

FERC's Order No. 2006 established procedures for processing interconnection requests specifically for small generators. It provides three ways to evaluate an interconnection request. One may be used by any small generator, defined as a generator under 20 megawatts in size. The second is for a generator no larger than 2 megawatts, and the third is a very simple process for most very small generators no larger than just 10 kilowatts. All three processes ensure that small generator interconnections will be studied faster than interconnections for large generators, and they also ensure that the interconnections will not endanger the safety of electrical workers or harm the reliability of the transmission system.

The commission's interconnection standards apply only to the public utilities FERC regulates and, with limited exceptions, only to interconnections to transmission facilities in interstate commerce as opposed to local distribution facilities.

However, the commission would regulate transmission interconnections to certain distribution facilities that serve a FERC jurisdictional function. For the commission's interconnection rules to apply, the generator must seek interconnection to a facility already subject to a FERC-approved open access transmission tariff and intend to make wholesale sales of energy.

Now, because FERC lacks jurisdiction over most local distribution facilities, the commission acknowledged in this rule the limited applicability of this rule for small generators. However, by developing a national interconnection rule through a process that sought industry consensus and by adopting many measures recommended by the National Association of Regulatory Utility Commissioners, FERC sought to harmonize State and Federal interconnection practices. FERC intended to promote consistent nationwide interconnection rules to help remove roadblocks to the interconnection of small generators. The commission expressed its hope that States would use FERC's rule as they formulate their own interconnection rules and thereby have a de facto national standard for small generator interconnection.

The same jurisdictional limitations apply to interconnections for net metering and for other distributed generation.

Net metering allows retail customers that have their own generation to get a retail rate credit for delivering their power output to their local utility. Net metering rules are subject to State or local rate jurisdiction unless a FERC jurisdictional wholesale sale of power occurs. FERC has held that such a wholesale sale does occur under net metering but only if the generator produces more energy than it needs for itself and makes a net sale of electric energy to a utility over an applicable billing period.

If there is a net sale of energy, the net metering generator or any other distributed generator must comply with the requirements of the Federal Power Act for wholesale power sales unless that generator happens to be a qualifying facility under PURPA, in which case the net sale must be consistent with PURPA and the commission's PURPA regs.

Thank you and I will be happy to answer any questions.

[The prepared statement of Mr. Kelly follows:]

PREPARED STATEMENT OF KEVIN A. KELLY, DIRECTOR, DIVISION OF POLICY DEVELOPMENT, OFFICE OF ENERGY POLICY AND INNOVATION, FEDERAL ENERGY REGULATORY COMMISSION

Introduction and Summary

Madam Chairman and Members of the Subcommittee, thank you for the opportunity to speak here today.

My name is Kevin Kelly, and I am the Director of the Division of Policy Development in the Office of Energy Policy and Innovation of the Federal Energy Regulatory Commission (FERC or Commission). I appear before you as a staff witness; my testimony does not necessarily represent the views of the Commission or any individual Commissioner.

My testimony briefly describes the Commission's rulemakings related to generator interconnection, with emphasis on the rule addressing the interconnection of small generators. It also describes the Commission's limited precedent regarding "distributed generation" and "net metering."

Generator Interconnection

Before a generator can make its energy available to wholesale or retail customers, it must interconnect to a utility's transmission or distribution system. A generator interconnection is the physical and contractual means by which a generator connects to—and operates as part of—a transmission or distribution system.

The Commission regulates certain generator interconnections pursuant to its authority under sections 205 and 206 of the Federal Power Act (FPA) to regulate the rates, terms, and conditions of transmission in interstate commerce by public utilities and pursuant to specific interconnection authorities granted to the Commission in sections 202(b) and 210 of the FPA. Interconnection authority under sections 202(b) and 210 is exercised on a case-by-case basis. However, pursuant to its authority to prevent undue discrimination under FPA sections 205 and 206, the Commission has acted generically to establish standard interconnection procedures to be included in the open access transmission tariffs of public utilities. The interconnection procedures minimize opportunities for undue discrimination and expedite the development of new generation. They also strike a reasonable balance between the competing goals of uniformity and flexibility while ensuring safety and reliability.

The Commission established its standard terms and conditions for generator interconnections to the transmission system in three rulemakings. The rulemakings followed consensus-building discussions among industry stakeholders regarding the best practices to include in the interconnection process. Order No. 2003, issued in July 2003, addressed large generators—that is, generators greater than 20 megawatts in size. Order No. 661, issued in June 2005, addressed technical issues particular to the interconnection of large wind resources. And Order No. 2006, issued in May 2005, addressed small generators—that is, generators less than or equal to 20 megawatts in size.

Small Generator Interconnection

Order No. 2006 established the procedures for processing and studying interconnection requests for small generators. It provides three ways to evaluate an interconnection request. First, there is a default Study Process that could be used by any Small Generating Facility. Second, there is a Fast Track Process for a Small Generating Facility no larger than 2 MW and, finally, there is a 10 kW Inverter Process for an inverter-based Small Generating Facility no larger than 10 kW. All three are designed to ensure, first, that the proposed interconnections will be studied more quickly than the procedures applicable to large generators and, second, that the interconnections will not endanger the safety of electrical workers or the reliability of the transmission system.

Order No. 2006 also established the contractual terms to be included in the interconnection agreement ultimately signed between the small generator and the public utility. The terms and conditions are streamlined and simplified versions of the terms and conditions for interconnecting large generators. But the agreement does not apply to interconnection requests submitted under the 10 kW Inverter Process, which uses a very simplified, all-in-one document for study, construction, and operation of an interconnection.

The Order No. 2006 small generator interconnection standards apply only to public utilities and, with limited exceptions discussed below, only to transmission (as opposed to local distribution) facilities used in interstate commerce. In Order No. 2006, as in Order No. 2003, FERC concluded that the FPA allowed it to require public utilities to offer generator interconnections to jurisdictional transmission facilities and to a very limited number of local distribution facilities on a nondiscriminatory basis. Local distribution facilities typically are low-voltage facilities used to deliver energy in one direction to retail end-users. The FPA expressly exempts local distribution facilities from FERC authority, except as specifically provided. Nevertheless, certain local distribution facilities do serve a FERC-jurisdictional function: for example, the same facilities used to distribute electric power to retail customers also may be used to deliver wholesale electric power to utilities. These local distribution facilities provide the second, FERC-jurisdictional delivery service under a FERC-approved open access transmission tariff. To determine whether a local distribution facility may be available for interconnection under FERC's interconnection rules, FERC asks this threshold question: is the local distribution facility already available for FERC-jurisdictional delivery service under an approved open access transmission tariff at the time the interconnection request is first tendered? If the answer is yes, and the generator plans to make wholesale sales of its energy, then the FERC interconnection rules apply. The Commission's assertion of authority over local distribution in these limited circumstances was appealed by the National Association of Regulatory Utilities Commissioners (NARUC) and six state regulatory agencies, and upheld by the Court of Appeals for the D.C. Circuit on January 12, 2007. (NARUC v. FERC, 475 F.2d 1299 (D.C. Cir. 2007)).

When the Commission adopted the same approach for small generators in Order No. 2006 as it had previously for large generators, it acknowledged the rule's limited applicability in light of its lack of jurisdiction over most local distribution facilities. It was expected that many small generators would interconnect to local distribution facilities not already subject to FERC's interconnection rules. However, by developing interconnection rules in a process that sought industry consensus, and adopting many measures recommended by NARUC, FERC sought to harmonize state and federal interconnection practices and promote consistent, nationwide interconnection rules to help remove roadblocks to the interconnection of small generators. To this end, in Order No. 2006, FERC expressed its "hope" that states would use the rule to formulate their own interconnection rules, and thereby make Order No. 2006 the de facto national standard for small generator interconnection.

Net Metering

Net metering allows retail customers that own generation to get retail rate credit for their output by effectively running the customer's meter backwards. Net metering rules are subject to state or local rate jurisdiction unless a FERC-jurisdictional wholesale sale of power occurs. In precedent established in 2001, FERC held that a wholesale sale of power occurs under net metering only if the generator produces more energy than it needs and makes a net sale of energy to a utility over the applicable billing period. (See MidAmerican Energy Co., 94 FERC ¶ 61,340 at 62,263 (2001)). If there are net sales of energy—and the generator is not a qualifying facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA)—the generator must comply with the requirements of the FPA for wholesale energy sales. If the generator is a QF, and there are net sales of energy, that net sale must be consistent with PURPA and the Commission's regulations implementing PURPA.

When a generator that wishes to engage in net metering seeks to interconnect to a transmission or local distribution facility, FERC would use the same analysis it uses to determine if its interconnection rules apply. In the Order No. 2003 proceeding, FERC clarified that for its interconnection rules to apply, the net metering customer—at the time it requests interconnection—must seek interconnection to a facility already subject to a Commission-approved open access transmission tariff and intend to make net sales of energy to a utility (Order No. 2003-A at P 747).

Distributed Generation

Distributed generation, as defined by the Department of Energy, is electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side or the customer side of the meter. Because the generator is connected to the distribution grid, the Commission's authority over distributed generation interconnections is limited and would be subject to the same analysis applied in Order Nos. 2003 and 2006. For the Commission's interconnection rules to apply, the distributed generation customer—at the time it requests interconnection—must seek interconnection to a facility already subject to a Commission-approved open access transmission tariff and intend to make wholesale sales of energy.

Regardless of whether a distributed generator is interconnected under FERC's rules, if the distributed generator makes wholesale sales of energy in interstate commerce and is not otherwise excluded from Commission jurisdiction by FPA section 201(f) or covered by PURPA, it must comply with the requirements of the FPA for wholesale energy sales.

QF Interconnections

A slightly different analysis applies to FERC's authority over interconnection of qualifying facilities under PURPA. FERC interpreted PURPA as establishing an obligation to interconnect (Western Massachusetts Electric Co. v. FERC, 165 F.3d 922 (D.C. Cir. 1999)). Under the Commission's regulations, when an electric utility purchases the QF's total output, the relevant state exercises authority over the interconnection terms and conditions. But when an electric utility interconnecting with a QF does not purchase all of the QF's output and instead the QF's owner sells or has a contractual right to sell any of the QF's output to an entity other than the electric utility directly interconnected to the QF, FERC exercises its authority over the rates, terms, and conditions affecting or related to the interconnection.

Thank you again for the opportunity to testify today. I would be happy to answer any questions you may have.

Senator CANTWELL. Thank you, Mr. Kelly, for your testimony.

Mr. Brown, proceed.

STATEMENT OF GARRY A. BROWN, CHAIRMAN, NEW YORK STATE PUBLIC SERVICE COMMISSION, ON BEHALF OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Mr. BROWN. Thank you. In addition to being the chair of the New York State Public Service Commission, I am also chair of the NARUC, National Association of Regulatory Utility Commissioners' Committee on Electricity.

So in both these roles, I think like much of the Nation, I have been following the energy and carbon debate that has been happening in Washington, and I have frequent interaction with my regulatory colleagues from around the Nation. I am struck by one thing. Almost everything currently being discussed and contemplated in the Federal venue, whether it is energy efficiency standards, renewable portfolio standards, smart grid initiatives, carbon reduction, net metering, fair interconnection standards, incorporation of distributed generation, and more, has really been dealt with at the State level to some degree or other. In fact, in New York State, we have addressed every one of these issues or at least started an initiative to address every one of these issues.

So I think there has been considerable experience that has been gained at the State level. All States have not taken the exact same approach at the same exact speed. That is not necessarily a bad thing. States are not always the same and circumstances are not always the same.

Our record has been, I think, on the most part, very supportive of increasing the diversity of supply in the electricity supply mix. So as you move forward with potential Federal legislation, I would ask you to please attempt to balance the need for Federal leadership and consistency with an awareness that there are many successful efforts at the State level that could be jeopardized by things that perhaps are overly restrictive or overly rigid rules that do not fit into a State's or region's circumstances.

Specifically on the issues that are the subjects of this hearing, over 40 States and the District of Columbia have already adopted net metering rules for distributed generation. Over 25 States have a renewable portfolio standard, with 14 of those containing specific provisions for solar in distributed generation. Thirty-five States, the District of Columbia, and Puerto Rico have adopted revised interconnection standards to ease the burden of safe interconnection into the electricity grid.

My written testimony highlights some of the benefits of increasing the role of distributed generation and net metering, our actions to address these issues. I think it also highlights some of the lessons learned along the way.

So the States welcome what I think we would describe is much needed Federal leadership on these energy issues and welcome you to the debate. We ask you to move forward with this leadership, however, with some flexibility. We will achieve our objectives I believe if we can avoid counterproductive jurisdictional debates and focus more on moving forward together to address these very important issues that are important both to the State and to the Federal Government that allow States some flexibility in moving forward while setting some national objectives that I think are very important for us all to go after.

So with that, I will conclude my testimony.

[The prepared statement of Mr. Brown follows:]

PREPARED STATEMENT OF GARRY A. BROWN, CHAIRMAN, NEW YORK STATE PUBLIC SERVICE COMMISSION, ON BEHALF OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Good afternoon Chairman Cantwell, Ranking Member Risch, and Members of the Subcommittee.

My name is Garry Brown, and I am the Chairman of the New York State Public Service Commission (NYPSC). I also serve as the Chairman of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Electricity.

Today I will be testifying on behalf of NARUC, and where noted the NYPSC. I am honored to have the opportunity to appear before you this afternoon and offer the State perspective on net metering and interconnection standards. I would respectfully request that my written testimony be entered into the record as if read.

DISTRIBUTED GENERATION

NARUC is a quasi-governmental, non-profit organization founded in 1889. Our membership includes the State public utility commissions serving all States and territories. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation.

Our members regulate the retail rates and services of electric, gas, steam, water, and telephone utilities. We are obligated under the laws of our respective States to ensure the establishment and maintenance of such utility services as may be required by the public convenience and necessity and to ensure that such services are provided under rates and subject to terms and conditions of service that are just, reasonable, and non-discriminatory.

NARUC and its members have long supported and encouraged advances in smaller, cleaner generation options. Distributed generation technologies are a resource that can function in a manner that results in a reduction in customer load, much like energy efficiency and load management technologies, with no export of power to the utility system. In addition, these distributed generation applications and technologies have many public interest benefits, such as:

- New technologies enhance customer choice;
- On-site generation improves customer value through control of costs and enhanced power quality and reliability;
- Distributed generation can enhance the efficiency, reliability, and operational benefits of the distribution system;
- Access to distributed generation technologies can increase competition by reducing the market power of traditional power providers, particularly in transmission and distribution-constrained regions;
- Generation close to load can reduce total electric generation costs by reducing line losses through the transmission and distribution system, and associated fuel and operational costs;
- Distributed generation allows utilities to improve the asset utilization of their transmission and distribution equipment and associated financial capital and operational expenses;
- Distributed generation resources can be permitted, installed and put into use more quickly than central station generation or transmission; and
- Distributed generation technologies can provide environmental benefits.

Recognizing the future importance and potential of Distributed Energy Resources to the nation's energy systems, in 2000, NARUC began to look at the potential barriers to distributed generation and found that:

- Burdensome distribution system operating and planning requirements may result in the unfair treatment of non-utility distributed generation technologies;
- Bundled distribution service tariff elements and fees and charges may present economic barriers to distributed generation technologies;
- Concentrations of market power may restrict the development of markets that distributed generation technologies could serve; and
- Ambiguous jurisdictional authority may hinder the business climate necessary for private investment.

Once the barriers where determined, NARUC's members started a three-year process to develop model interconnection standards for small generation resources in an attempt to produce a document that would remove or alleviate most of the access issues and fit the regulatory systems in the vast majority of the States.

This process, as well as the Federal Energy Regulatory Commission (FERC) order 2006 process, which had extensive State involvement and coordination, greatly improved the promise of new and cleaner distributed generation technologies—like fuel cells, micro-turbines, distributed wind machines, and photovoltaics—by working to significantly reduce market barriers that existed due to inconsistent and outdated grid interconnection standards.

As a result of these activities and passage of the Energy Policy Act of 2005, today approximately 35 States and the District of Columbia, including the major load centers in the nation, have interconnection standards.

In New York, the existing Standard Interconnection Requirements (SIR) for distributed generation 2 MW and under has separate and distinct review processes for systems 25 kW or less, and greater than 25 kW up to 2 MW. Systems 25 kW or less will have a streamlined application process, and systems above 25 kW up to 2 MW will have more detailed review process.

NYSPSC staff has proposed that utilities be required to implement a web-based system for providing generator customers and contractors up to date information regarding the status of their application process. In addition, the staff has proposed that each utility be required to allow customers with systems 25 kW and below the ability to submit their application for interconnection via the Internet. These proposals are under consideration.

NET METERING

Net energy metering—an accounting mechanism whereby customers owning qualifying generators are billed only for their net energy consumption over a given billing period and obtain a credit for future billing periods if production exceeds consumption—can provide a direct, inexpensive, and easily-administered mechanism for encouraging the customer installation of small-scale renewable energy facilities.

Public preference and customer demand support cost-effective renewable energy product development and commercialization. The use of customer-sited, grid-connected, small-scale renewable energy generating facilities offers many technical and economic benefits to the electricity system including reduced transmission and distribution line loads and losses, and/or peak demand reduction.

Approximately 40 States currently require utilities and competitive energy providers to make net energy metering available, and another four permit it under voluntary utility programs.

While the capacity limits, and other terms and conditions vary among States, these differences reflect the programs that work the best for the consumers of a given State. These variations ensure that the consumers of each State receive just and reasonable rates, at fair terms and conditions. In addition, since NARUC began to seriously study net metering proposals in 1998, the States have made great progress in this most useful retail rate-design mechanism.

In New York, net metering is legislatively mandated and encourages the use of small-scale renewable energy systems which provides long-term benefits to the environment and the economy.

Recently, Governor David A. Paterson announced an expansion of the state's net metering law, which allows electric customers who generate renewable energy to sell what they do not use back to the grid. The new bill expanded net metering to wind and solar PV systems on businesses, as well increasing the size of eligible systems for residential customers and for non-residential customers.

New York has a strong legislative history regarding net metering:

1997—Initial legislation providing net metering for small (up to 10 kW) solar generators

2002—Net metering expanded to include individual anaerobic digester (farm waste) electric generators up to 400 kW

2004—Net metering expanded to include up to 25 kW residential and up to 125 kW residential farm service wind generators

2008—Net metering expanded to provide to commercial solar and wind generators up to the lesser of the most recent 12-month peak load or 2MW; residential solar installations increased from up to 10 kW to up to 25 kW; residential farm service wind installations increased from up to 125 kW to up to 500 kW; and anaerobic digester (farm waste) installations increased from up to 400 kW to up to 500 kW.

The overall cap for solar and farm waste generators is 1 percent of each utility's 2005 peak load on a first-come, first-served basis. The overall cap for wind generators is 0.3 percent of each utility's 2005 peak load on a first-come, first-served basis.

In New York, customers get credit at retail rates for excess generation subsequently used by the customer for its own purposes during a 12-month period. At the end of the 12-month period, for residential and farm customers, any remaining excess generation is credited at the market or wholesale rate. For non-residential solar and wind technologies, any remaining excess generation is rolled over to the next 12-month period.

As Congress considers what role it might want to play in terms of net metering policies, perhaps it would be helpful to hear briefly policy questions we are asking in New York as we weigh the benefits of potentially expanding net metering even further. These policy questions include:

- Should net metering be provided to customers who also have non-qualified generators?

- Should we expand net metering technologies to include additional technologies and/or should the sizes of the allowed technologies be increased?
- How should potential impact on non-participants be mitigated?
- What are the possible impacts on transmission and distribution systems?

We have also learned several lessons in implementing net metering in New York:

- Overly restrictive definitions of the metering configurations net metering customer must use should be avoided. A restrictive definition could impede customer efforts to avail themselves of smart metering options, which could assist customers in maximizing the benefits of net metering.
- The eligibility criteria customers must meet to qualify for net metering should be developed carefully to avoid unintended consequences.

In conclusion, states have been a very successful laboratory for distributed generation and retail rate design policies. Certainly, more can and will be done in the near future. However, these issues will affect not only the entities that hopefully will make a profit to continue the development of renewable generation sources based on these policies, but also those consumers who will pay these costs.

Thank you for your time and consideration.

Senator CANTWELL. Thank you, Mr. Brown. Perhaps we can get more into that in the question and answer session after the rest of the witnesses.

Mr. BROWN. I would be happy to.

Senator CANTWELL. Thank you.

Mr. Cook.

STATEMENT OF CHRISTOPHER COOK, MANAGING DIRECTOR, SUNWORKS, LLC, DUNN LORING, VA

Mr. COOK. Thank you, Madam Chairman, fellow members of the committee. My name is Chris Cook. I am a co-founder and Managing Director of Sunworks, a startup company focused on bringing photovoltaic manufacturing facilities to the U.S.

I am also here on behalf of SEIA, the Solar Energy Industries Association, the national trade association for solar manufacturers, installers, and developers.

My comments today are focused on net metering and interconnection, but I would be happy to discuss with you anything about distributed generation. I am honored to have this opportunity. I have been working on net metering and interconnection issues for over a decade and have worked with nearly 20 States on implementing either net metering or interconnection rules in the State.

My overarching point is it is imperative, if we are going to meet the President's laudable renewable energy goals to address these issues, to have a seamless interconnection and net metering rules across the States that do not create a barrier for the people like my company who want to install solar energy systems on rooftops.

I will give you as an example the current state of affairs. While 42 States have net metering—and there is some debate over just the precise number of which States do have and do not have—my former company, Sun Edison, focused on commercial rooftop installations of 100 kilowatts or larger. When you look at the details of the State net metering rules and then you look at that business opportunity or that business plan, roughly half the States fall out for a net metering opportunity because they do not allow net metering for systems above 100 kilowatts.

If you then focus on the half that are remaining, an additional five States fall out because even though they have good net metering rules, they have interconnection rules that constitute a barrier for those larger-size systems.

So while at first blush it appears there are 42 States in which a company like Sun Edison might do a robust business, it turns out when you actually get into the details of the rules and the patchwork that you mentioned, there are really only 16 States where a company focused on commercial installations can do business currently. I think that is an overarching call-out for some Federal leadership and Federal guidance that provides a seamless web across all States so that solar energy companies can do business there.

Elements of a good net metering policy. I think the main opposition to net metering, a nationwide net metering, is the proposition that if you put power back onto the grid from your solar energy system, the people who operate the grid say that power is not worth the same amount as the power that they provide you because the per kilowatt hour charge that is charged to retail customers are fixed costs. Part of the difficulty then is to say, well, how much is that power worth? When it comes to solar, there is lots of indirect benefits that accrue for the power that is put onto the grid.

First, solar is a peak energy generation technology, and peak generation tends to be much more valuable to the grid than off-peak generation. So a solar energy producer might have a 125 or 150 percent adder to the value that they are actually putting to the grid.

Then there is a host of intangible benefits that accrue to the grid. There is offset need for transmission and distribution upgrades. There is offset wear and tear on the grid from the power that goes there. The power is utilized locally so there are offset transmission charges.

So the issue then comes down to say is it approximately equal. I would submit to you that it is, that the power of the solar generators, particularly when you look at the emissions benefits, put onto the grid is equal and that net metering is a good approximation for it. That is really the main opposition to it is the economics behind it.

I think what is needed from a Federal level is a Federal guide on net metering. While, as Mr. Kelly explained, the FERC has weighed in and has effectively a Federal guide on interconnection, there is no Federal guide on net metering. So States that move forward to adopt their own net metering rules really do not have an effective Federal leadership guide to say what constitutes good net metering and what is a core.

I would recommend that the FERC be tasked with the authority of coming up with a model, having that model at its core remove the barriers to the net metering issues. States have the flexibility to aggrandize that or add enhancements, but FERC then retains the authority to say if a utility adopts a net metering tariff, it still constitutes a barrier so that people can install solar on their homes or businesses. The FERC would have the authority to implement the model rules.

I think a similar structure would work on the interconnection, and while FERC did a laudable job on that in 2003, I think the rules could use some updating. There was a segment of the interconnection rules that the working groups just simply ran out of time and never got around to. Those could use some updating.

I think it would behoove the FERC to look at some of the State interconnection proceedings that have gone subsequent to FERC Order 2006 and adopt some of the consensus best practices that came out of those State proceedings to update their model rule and, then again, use that model rule for the States to roll out so that we can attempt once again to get what I think FERC articulated in their Order 2006 with a seamless national web for interconnection standards for small generators.

Thank you.

[The prepared statement of Mr. Cook follows:]

PREPARED STATEMENT OF CHRISTOPHER COOK, MANAGING DIRECTOR, SUNWORKS, LLC, DUNN LORING, VA

Madam Chairman, members of the Subcommittee, thank you for the opportunity to testify today. I am here on behalf of my company and on behalf of the Solar Energy Industries Association who is the leading national trade association for the solar energy industry. SEIA works to expand markets for solar, strengthen research and development, remove market barriers and improve public education and outreach for solar energy professionals. SEIA has over 900 member companies representing the entire spectrum of the industry, from the small installers to large multinational manufacturers.

Access to net metering and standardized and streamlined interconnection standards are critical to the widespread deployment of customer sited solar and other renewable energy generators. While a total of 42 states have net metering and every state has some form of interconnection rules, the rules vary widely. Some encourage the use of renewable energy generators while others hamper the national deployment of solar. I will herein describe in Section I the important aspects of net metering. In Section II I will discuss the need for comprehensive national standards for interconnection of small generators.

SECTION I: NET METERING—WHAT IS IT?

Net metering is an economic arrangement between a customer who owns or operates their own generator ("customer generator") and their local utility to effectuate the operation of the customer-generator's generator. It is distinguished from interconnection standards which are the technical and safety requirements needed to connect a generator that will interact with the utility grid in a mode the industry calls "parallel operation". While any generator that will avail itself of a net metering must be interconnected, an interconnected generator may or may not operate under a net metering tariff. It is important to distinguish between the two.

The term "net metering" derives from a simple utility metering system where a single meter spins forwards when a customer is using more electricity than they are generating and in reverse during those times when the generator output is greater than the customer's load. Because the meter spins forwards and in reverse the meter itself "nets" excess consumption and generation and the meter reading shows the net of generation and consumption over any discreet billing period.

Interestingly, the simple meters typically deployed by utilities in the 1950's and 1960's with the spinning disk would net meter. All of these meters would simply spin in reverse when a generator on the customer's side was producing more power than the customer was using.

WHY IS NET METERING NEEDED?

For renewable generators like solar and wind, the renewable generator operates when the resource is available and cannot be throttled up or down to match the load at the customer's home or business. That means that at any given time there is a high probability that the generator is either producing more than the customer needs or less. When the generator is producing more power the customer has three choices:

1) the customer can install a storage device (e.g. batteries) and send the excess power to storage to be used later.

2) the customer can turn on more electricity consuming equipment to use the excess power (not generally encouraged).

3) the customer can send the power to the electric grid for use by other customers.

Under option 3—the net metering option—the customer is credited for the power to the grid and can use those credits later to offset future costs and lower their electric bill. Option 3 is the lowest cost option for the customer and in the case of solar generators the best option for the utility grid.

A standard net metering tariff allows the power producer to obtain full value for all of their power produced without the excess cost of installing batteries or other storage devices.

WHY IS THEIR OPPOSITION TO NET METERING?

The rate that a utility typically charges a customer for kilowatt-hours (kWh) consumed by the customer includes fixed charges. When a customer produces their own energy (kWh) and receives a full retail credit for excess kWh, the utility has a reduced revenue source for the fixed cost component of providing electric service. These lost contributions to fixed costs are born by the utility until their next rate case at which time other customers would pay an incrementally higher percentage of the fixed costs to make up the loss from the net metering customers.

This raises the largest question about net metering—whether power producers that are benefitting from net metering are paying their fair share of system costs. There is no clear answer and to the best of my knowledge, no comprehensive study has ever been undertaken to address and potentially resolve this issue.

Part of the reason the question cannot be answered simply is that net metering customers provide a host of indirect benefits to other utility customers. In the case of solar customer-generators these benefits include:

- reducing peak demand,
- avoiding environmental damage,
- improving grid efficiency,
- avoiding upgrades to transmission and distribution grid,
- providing local voltage support that can reduce the need for other utility equipment,
- reducing the need for operating and spinning reserves needed to assure electric reliability,
- the ease of deploying solar projects and their short lead times reduces the risk of forecasting mistakes that can result in costly power generation overcapacity[1].

All of these benefits go to reducing and perhaps eliminating any subsidy from non net metered customers. In fact, it may be true that net metering customers are subsidizing other customers.

In case there is a cross subsidy, net metering rules typically limit the total amount of customers who can net meter. For example, a state might limit net metering to five percent of the total capacity of generation on a utility system. This ensures that if there is a net metering subsidy, any subsidy is tiny and of minimal impact on other customers.

It is also worthy of note that net metering provides no worse an economic arrangement for the utility and other customers than the alternative presented to the customer-generator—storage.

If a customer-generator were to install a storage device for all of their excess production, they would cease to contribute to fixed costs for any of the kWh they produced (in an identical way, a customer who reduces their consumption through energy efficiency also contributes less to fixed utility costs). For the solar generator with storage, the situation becomes worse for other customers. Because solar generation typically occurs during the more costly peak times, the solar customer-generator is invariably producing excess power during the most costly periods for grid electricity while consuming excess net metering credits during off-peak periods. When the solar customer "net meters", the excess peak energy is sent to the grid and other customers see the benefit of this peak energy generation.

If a solar customer-generator were to instead use storage, they would be storing peak energy for off-peak usage. This is quite contrary to all grid storage strategies which store off-peak energy for on-peak usage. So were net metering not offered and customers were driven to an on-site storage option, other customers would be worse off than if net metering is used.

[1] From A WHITE PAPER By ED SMELOFF, "QUANTIFYING THE BENEFITS OF SOLAR POWER FOR CALIFORNIA"

WHY IS A FEDERAL STANDARD NEEDED?

While 42 states have some form of net metering in place, no two are the same. Some state net metering rules are robust and can be said to encourage a wide array of renewable energy deployment by customers. Others are quite limited and act as barriers to the widespread use of solar energy. A ranking of the states showing how they compare against each other was performed by the Network for New Energy Choices and is attached to my testimony as Appendix A. It is my understanding that a grade of "C" under this ranking represents a functional standard for most customers. Lower grades mean the state's rule contains some major and minor barriers.

A minimal federal standard that allows all customers to use solar energy for their electricity needs is critical to the growth of the solar industry. A federal standard will remove barriers that currently exist in the myriad of state net metering standards. While states should be encouraged to go beyond the minimal federal standard to actually promote the use of renewable energy, the industry needs a federal standard that removes all major barriers nationwide.

Key elements of a functional federal standard:

- 1:1 ratio of credit to kWh produced. A customer should see no reduction in the value of the power they produce. Not only is a lower ratio a deterrent to the use of renewable energy, it incurs extremely high administrative costs to implement. If those administrative costs are placed on the net metered customer, they often lose much of the value of the renewable energy they produce.
- Time of use open to net metering customers at an equivalent to the time of production and consumption. Where time of use rates are in place, a renewable customer-generator should get a peak credit for any excess peak power produced to be used to offset peak power consumption. The same is true for mid-peak and off-peak periods. If the peak power costs, for example, 2 times the mid-peak, the net metering customer should get 2 mid-peak credits in consumption for every peak credit they produce.
- Safe harbor provisions. A customer-generator should not be charged any special fees or other charges to have access to net metering and should be treated identically in terms of rates and other conditions of service to a similarly situated customer that does not have a renewable generator.

RECOMMENDATION ON GENERATOR SIZE LIMITS

The size of a customer-generator's generator does not impact the economic equation related to potential cross-subsidy discussed above. Therefore the size limitations on net metering generators should skew to the large to allow all customers to offset a substantial portion of their electricity needs. While the recent trend among states is to set the upper limit on the size of generator at 2 megawatts, several states have gone well above that limit. In addition, the size of solar generators at customer sites are trending to the larger sizes with the largest customer sited solar generator at the Nellis Air Force base in Nevada coming in at 14MW. To allow room for this growth to continue, I would recommend a 10MW limit on the size of the net metered generator.

RECOMMENDATION ON TOTAL CAPACITY

To allow both for sufficient growth in the solar (and other renewable) industry, I would recommend that the total installed capacity limit for all net metered generators be set at 5 percent of the capacity of any individual utility system. This limit ensures that a cross subsidy, if any exists, is small while at the same time allows for a decade's worth of growth in the industry. Even if the power exported to the grid is only worth the wholesale power rate (about half the net metering credit), that means the total cross subsidy is less than 2.5 percent. It is less both because of an assumption that the aforementioned list of benefits are worth something more than zero and because a capacity limit does not account for the many installations that will be exporting no power to the grid and hence incurring no subsidy (many solar installations at commercial and industrial sites never export to the grid even though they use a net metering tariff).

RECOMMENDATION ON IMPLEMENTATION

To avoid supplanting state work on net metering completely, I would recommend that the Federal Energy Regulatory Commission (FERC) be tasked with creating a model net metering tariff for states to use that eliminates all major barriers sometimes buried in net metering rules. States and utilities will then have a useful guide to creating their own net metering rules and will have the flexibility to go beyond the model to adopt rules that promote renewable energy. FERC should have the authority to order the adoption of the model rules in those cases where it determines, after hearing, the net metering rules of any particular utility constitute a barrier to the use of renewable energy.

OTHER POINTS

1) Net metering should address solely the economic arrangement for renewable customer-generators. Any technical or safety related issues including the types of equipment needed to interconnect and the costs for interconnection studies should be addressed in the interconnection standards.

2) Net metering should not be considered a buy and sell arrangement between the customer and utility. To simplify the entire transaction and avoid transactional costs, net metering should be constructed as a "swap" of kilowatt-hours where the parties receive kWh at a certain point in time to be consumed at a later point in time. When there is no buy-back or selling of kWh, there are no checks to be cut and no accounting ledgers to maintain. In the simplest and perhaps easiest form to implement net metering, excess kWh credits are simply carried forward month to month to be used by the customer at some time in the future. When the customer departs as a utility customer, any unused credits disappear.

INTERCONNECTION STANDARDS

Interconnection standards, unlike net metering rules, address technical, safety and contractual issues surrounding operation by a customer of any type of generator that generates in parallel to the utility grid. This includes generators sited at a customer's location that export power to the grid; generators sited at a customer's location that do not (and in some cases cannot) export power to the grid; and generators that are not at a customer site but are connected to the grid and export power. Interconnection standards typically address the smallest home generators in the kilowatt range to gigawatt sized generators.

Interconnection is accomplished by having the local utility "study" the impacts on the grid of connecting the proposed generator. Where the generator is small in relation to the capacity of the grid, the interconnection may be approved without any grid improvements. Where the new generator may overload utility protective devices or lines, the utility, at the generator's cost, will have to upgrade those devices or lines before the interconnection can be approved. The interconnection study process for the latter may take months and costs tens of thousands of dollars to complete.

SECTION II: INTERCONNECTION STANDARDS—THE NEED FOR A COMPREHENSIVE FEDERAL SMALL GENERATOR INTERCONNECTION STANDARD

FERC in its Order No. 2006[2] (et. seq.) created a small generator interconnection procedure (SGIP) that all federally regulated utilities were required to adopt. This standard was the result of a long series of stakeholder meetings FERC held subsequent to the issuance of its Notice of Proposed Rulemaking (NOPR) on small generator interconnection standards. The rules are generally comprehensive but are lacking in three distinct areas:

1) Order No. 2006 does not provide for standardized interconnection procedures for customer sited generators that will not export power to the grid. The stakeholder process that led to Order No. 2006 was limited in time and this aspect of the procedures was simply left unaddressed because of the time constraints. Larger combined heat and power generators typically fall into this category and at present there is no federal standard that expedites the interconnection of these generators. With the increasing size of solar generators, they too may soon find need for the interconnection rules for larger generators.

2) Updates from state interconnection proceedings. Many states have undertaken interconnection proceedings subsequent to issuance of FERC Order No. 2006 many of which have expanded upon and added refinements to the original FERC Order. FERC should revisit its Order to include the best practices from the state proceedings and their interconnection rules.

3) Order No. 2006 is not comprehensive in its application. While the SGIP addresses any interconnections to federal transmission facilities and those dis-

[2] Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, 70 FR 34100 (Jun. 13, 2005), FERC Stats. & Regs., Regulations Preambles, Vol. III, ¶ 31,180, at 31,406-31,551 (2005).

tribution facilities under an open access transmission tariff, most of the interconnections of customer-sited generators are not to these types of facilities. Not only does this leave potential gaps in the size of generators that can be interconnected but, like net metering, the state rules are a myriad of different regulations. Some state interconnection rules are quite accommodating to small and renewable generators while others constitute barriers. Irrespective of the good or the bad, the patchwork of state rules in this area represent a restraint on the ability of solar developers and manufactures to freely conduct interstate commerce. Many manufacturers of interconnection equipment for solar generators must take into account these varying state rules which adds costs to the systems they are trying to stamp out. A universal federal standard is needed.

WHAT ARE THE KEY ELEMENTS OF GOOD INTERCONNECTION PROCEDURES FROM SMALL GENERATORS?

Interconnection rules can be a costly, time consuming, and arcane set of rules to follow for even the simplest small and renewable generators. The key to accommodating small generators is to identify a set of circumstances that allow the generators to be interconnected quickly and at low cost. Because solar and other renewable generators often use specialized electronic devices (inverters) to oversee the generators interactions with the grid, a number of utility safety and technical concerns are easy to address. Moreover, when the inverter devices are UL certified, the interconnection process can be nearly "plug and play". A series of quick engineering screens can be used which will either determine that the generator can be approved for interconnection or that additional study is needed.

The overarching objective in designing good and streamlined interconnection rules is to avoid unnecessary interconnection studies that, based on solid electrical engineering principals, do not need to be conducted. For example, while it may be academically interesting to see how that single installation affects power flows on a nearby transmission line for a small solar installation on a residential rooftop, the likelihood that that would ever occur is nil. Undertaking an engineering study to confirm that assumption would be both time consuming and costly for the residential customer. Such a study is unnecessary and should be excluded from good interconnection procedures.

Other elements that distinguish good interconnection rules from bad ones are:

- Some element of fixed cost to complete the interconnection study process that allows a solar developer to have a good idea of the cost to complete the interconnection study process
- Fixed timelines for the utility to complete interconnection studies so developers can know for certain the latest when their generator will be approved for operation.
- Prohibition on utility requirements to add additional and unnecessary protection equipment that increases the cost of a solar installation.
- Simplified and standard form interconnection agreements so each installation does not need to budget for legal counsel to assist in negotiating an interconnection contract.
- Prohibition on requirements for insurance above and beyond ordinary liability insurance.
- A dispute resolution process where a solar installer can have access to a knowledgeable expert or master who can resolve quickly and at little cost disputes over the interconnection requirements. Since solar installers and developers are almost always less capitalized, and have less expertise on staff, they may find their interconnection request at the mercy of a recalcitrant utility who has little interest in seeing the solar installation progress

The overarching need of the solar community and other generator project developers is to have comprehensive rules that cover all generator interconnections. Unfortunately in many instances local rules act as a major barrier to the use of renewable generation.

CURRENT STATE OF INTERCONNECTION

Unfortunately, while several states have implemented comprehensive rules on interconnection, according to the NNEC report (Appendix A*), only 15 states have interconnection rules that can be said to have eliminated all major and minor barriers to the interconnection of small generators. Just over half the states continue to have interconnection rules that constitute, to some degree, a major barrier to

*Report (Appendix A) has been retained in subcommittee files.

interconnection. This either prevents homeowners and businesses from using their own solar or renewable energy generator or significantly increases the time or cost to do so.

This is all the more unfortunate in light of the universal and functional FERC small generator interconnection procedures and the directives in EPAct 2005 to address interconnection.

RECOMMENDATION FOR COMPREHENSIVE INTERCONNECTION RULES

I would recommend that FERC be directed to reconvene working groups to update and complete the Small Generator Interconnection Procedures contained in FERC Order No. 2006. FERC should look to the state proceedings to include consensus best practices from recently promulgated state interconnection rules. A good guide and compilation of those best practices is found in the Interstate Renewable Energy Council's (IREC) model interconnection rules (IREC MR-I2005). IREC has a team of experts that not only work with states on creating interconnection rules but also update their model rules when a new best practice is developed.

After FERC has updated the SGIP, it should present that as a model for states and local utilities to adopt. As with net metering, FERC would retain jurisdiction and be able to require a utility to adopt the updated model interconnection rules where the rules otherwise adopted by the utility represented a barrier to the use of renewable generation. FERC should be tasked specifically with ensuring comprehensive and seamless interconnection standards irrespective of whether the interconnection is local or under traditional FERC regulation.

Senator CANTWELL. Thank you, Mr. Cook.

Mr. Weiss, thank you for being here today.

STATEMENT OF DAVID WEISS, PRESIDENT AND COO, ENERGY SERVICES DIVISION, PEPCO ENERGY SERVICES

Mr. WEISS. Thank you. Chairman Cantwell, Senator Bingaman, my name is David Weiss. I am President and Chief Operating Officer of Pepco Energy. Pepco Energy is an unregulated subsidiary of Pepco Holdings. We provide retail energy services and products, including energy efficiency. We develop renewable energy projects, district heating and cooling projects, and distributed generation projects.

I am pleased to appear before you this afternoon to discuss distributed generation's potential to increase clean energy deployment and to diversify our Nation's energy supply.

Pepco Energy has executed a number of very interesting projects, and I would like to describe a few of them to you today because I think it will help you get a feel to how these work.

In December 2008, Pepco Energy completed an installation of the largest single rooftop solar project in the country in Atlantic City. This project covers 266,000 square feet of rooftop. That is equivalent to five football fields. The 2.37 megawatt DC project at the Convention Center in Atlantic City includes net metering. The project was made possible by the fact that there are times during the year where we provide more electricity to the Convention Center than required, and it is then exported to the grid through net metering and smart meters. The project was really made possible by Federal tax incentives, the State of New Jersey renewable portfolio standards, the New Jersey net metering regulations, and interconnection agreements.

Another project we did, which was a distributed generation project at the NIH, a 2-megawatt co-gen project, did not require net metering because it produces less than the base electricity use of the campus.

The third project, or group of projects, is three landfill gas-to-energy projects up and down the mid-Atlantic region, including 10 megawatts of generation. All these plants required separate interconnection agreements because we were in three different investor-owned utilities.

Finally, we also own a large district heating and cooling plant in Atlantic City where we deliver chilled and steam water for heat and air conditioning to many of the casinos of the boardwalk. At this time, we have no distributed generation in this 12-year-old facility, but we intend to install it in the near future. In order to do that, we will either need net metering capabilities or the capability to send electricity, along with the steam and chilled water, to an adjacent property.

With that background in mind, I would like to explain some of the challenges of these projects and some of the policies and issues that arise.

Distributed generation and net metering are and can be a significant, valuable component of our overall energy mix. In order to promote distributed generation, the market needs to be confident that the real and perceived barriers of generation policies with rate decoupling can be accomplished. Rate decoupling means that the local utility is indifferent to how much energy it sells. Whether it sells more or less, it still gets a rate of return on its assets and, therefore, is less worried about small generation and energy efficiency projects.

A second area is standardization to the greatest degree possible. Standardization of the interconnection agreements will very much help the industry move quicker and develop distributed generation and renewable energy projects quicker.

Each one of these projects out there have their own unique benefits and constraints, and there are a lot of stakeholders in these projects, the local utilities, the local customers, the local citizens. So although a model can address many of the best industry standards and practices, there has to be some allowance for local flexibility for safety and also just for the local stakeholders to make sure that they are comfortable with the systems.

In closing, Chairwoman Cantwell, I would like to thank you and the subcommittee for the opportunity to speak here today. As evidenced by the work we have been doing and continue to do at Pepco Energy, I feel strongly that the use of energy resources, diversity in the energy generation and renewable energy, coupled with strong enabling policies are of extreme importance to the energy environment in which we now find ourselves. Thank you.

[The prepared statement of Mr. Weiss follows:]

PREPARED STATEMENT OF DAVID WEISS, PRESIDENT AND COO, ENERGY SERVICES DIVISION, PEPCO ENERGY SERVICES

Chairwoman Cantwell and Members of the Subcommittee, my name is David Weiss and I am the President and COO of the Energy Services Division of Pepco Energy Services. Pepco Energy is a subsidiary of Pepco Holdings Inc., one of the largest energy delivery companies in the mid-Atlantic region.

Pepco Energy provides retail energy products and services, including comprehensive energy management solutions and renewable energy projects to a wide range of customers that includes the Statue of Liberty, the U.S. Capitol, The Empire State Building, the US Air Force, Army and Navy and many state, municipal, commercial and industrial customers. Over the last 14 years, Pepco Energy has developed, implemented and financed over $750 million in energy savings performance contracts including the single largest one ever awarded by the federal government. In addition, Pepco Energy is an experienced developer of renewable energy, district heating and cooling and distributed generation projects.

Pepco Holdings other subsidiaries serve about 1.9 million customers in Delaware, the District of Columbia, Maryland and New Jersey operating as Potomac Electric Power Company (PEPCO), Delmarva Power and Atlantic City Electric which provide regulated electricity service; Delmarva Power also provides natural gas service. Pepco Holdings additionally provides competitive wholesale generation services through Conectiv Energy.

I am pleased to appear before you this afternoon to discuss distributed generation's potential to increase clean energy deployment and to diversify our nation's energy supply, particularly in parts of the nation, like the mid-Atlantic that are not benefitted with a tremendous supply of renewable resources. Pepco Energy has executed a number of very interesting distributed generation projects and I'd like to take a moment to describe how three of them work.

In December 2008, Pepco Energy completed the installation of the largest single roof- mounted solar project in the country in Atlantic City, New Jersey. The project covers over 266,000 square feet on the roof of the Atlantic City Convention Center. The 2.37 MW-DC solar generating system includes over 13,400 panels and is designed to provide approximately 26% of the Convention Center's annual usage. This project made use of net metering by actual "smart meters" that measure the power being imported to the facility and exported from the facility. The renewable energy generated avoids the release of approximately 2,349 tons of carbon dioxide per year. This project represents a substantial investment by our company in renewable energy, and could not have been accomplished without the coordination of a number of different parties; the local utility, various state agencies, and, of course, the host customer. The project returns were dependent on the utilization of a number of different policies and programs including federal tax incentives, the State of New Jersey's Renewable Portfolio Standards, net metering regulations and interconnection agreements.

A second project is a 23 MW gas-fired cogeneration plant at the National Institutes of Health in Bethesda, MD. This project was completed in 2004, and is one of the largest cogeneration facilities ever built for the Federal government. Situated in the middle of a densely populated area, and in an extremely active campus setting with a significant amount of critical infrastructure to protect, careful attention had to be paid to the local community concerns, as well as the safety and reliability of the unit and the existing, surrounding infrastructure. This output from this unit will result in a significant amount of savings to NIH, and will reduce carbon dioxide emissions by approximately 100,000 tons per year over its 20-year life. This project did not require net metering because the unit produces less than the base load energy use of the NIH Campus.

A third project-or group of projects-is our landfill gas-to-energy plants. Pepco Energy has designed, built, owns and operates 3 of these landfill gas plants in the mid-Atlantic area, with a combined generating capacity of 10 MW. While the plants use a variety of technologies to capture, condition and utilize the methane from these landfills, they each have one thing in common: they take an otherwise unused, and harmful byproduct of the landfill and turn it into a valuable and useful commodity that improves and diversifies our energy mix in the U.S. Each one of these facilities is in a different investor owned utility's service territory and therefore we were required to negotiate a special interconnection agreement for each project.

In addition to these projects, Pepco Energy owns and operates a large district heating and cooling plant in Atlantic City, New Jersey that delivers steam and chilled water to many of the casinos on the boardwalk for their heating and air conditioning needs. At this time, there is no distributed generation included in this 12 year old plant, but we do have plans to add a cogeneration unit in the near future that will significantly increase the efficiency of the plant and may require net metering capabilities.

With that background in mind, please allow me to explain some of the challenges of these projects, and some of the policy issues that arise.

Distributed generation and net-metered generating systems are and can be a significant and valuable component of our overall energy mix. In order to promote the use of distributed generation the market needs to be confident that the real or perceived barriers to quick implementation of projects have been removed. Combining strong pro-distributed generation policies with rate decoupling will accomplish this task. Under rate decoupling, utility companies are indifferent to the volume of electricity that their customers consume, as their profitably is less likely to be impacted, positively or negatively, by changes in consumption. By supporting and instituting rate decoupling, in combination with strong pro-distributed generation policies, I believe a significant opportunity exists to help strengthen and diversify our energy mix, whether it's more cogeneration, distributed generation, renewable generation, or more energy efficiency.

A second area to address is standardization to the greatest degree possible, across state and utility borders. There is much to be gained by adopting simplified and standard approaches to distributed generation related issues. However, it is important to remember that any distributed generation project, such as those I discussed previously, brings together and impacts a variety of stakeholders; the host customer, the local utility, the state, the local citizens, and often overlooked, the local utilities of other customers. Each project, each location, each customer has its own unique benefits and constraints, and any standardization across territories must take this diversity into account. For this reason, I believe that a federal model for net-metering and interconnection standards for distributed generation projects is an extremely important component that needs to be addressed. This model should be based on industry best practices, and possibly provide incentives to facilitate the adoption of these standards. However, I believe the model should allow for the flexibility in the system, and also allow all the local stakeholders the opportunity to influence and impact the policies that directly affect their local area.

In closing, Chairwoman Cantwell, I'd like to thank you and the Subcommittee for the opportunity to speak with you today. As evidenced by the work we have been doing and continue to do at Pepco Energy, I feel strongly that the efficient use of energy resources and diversity of energy generation sources, coupled with strong enabling policies, are of extreme importance in the energy environment in which we now find ourselves.

Thank you and I'd be pleased to answer any questions.

Senator CANTWELL. Thank you, Mr. Weiss.

Ms. Kowalczyk, thank you.

STATEMENT OF IRENE A. KOWALCZYK, DIRECTOR, ENERGY POLICY AND SUPPLY, MEADWESTVACO CORPORATION, GLEN ALLEN, VA

Ms. KOWALCZYK. Chairwoman Cantwell, members of the subcommittee, I very much appreciate the opportunity to testify before you today. I am employed by MeadWestvaco Corporation, a global leader in packaging and packaging solutions with $6.6 billion in revenue, 22,000 employees worldwide. We are members of the Industrial Energy Consumers of America, IECA, a trade association on whose behalf I am also testifying.

The purpose of today's hearing is to consider policies that promote the deployment of distributed generation because of the numerous environmental and other benefits distributed generation provides. Today I will focus on just one kind of distributed generation, co-generation, which is also called combined heat and power, or CHP.

CHP allows a manufacturing facility or a commercial building to recycle its waste energy to very efficiently produce power and steam energy. CHP technology produces power that is at minimum 100 percent more energy efficient than technology used by the electric utility industry and it significantly emits less carbon dioxide air emissions and uses less water. The technology is commercially available and extraordinarily reliable.

The problem is that over the last several years, Federal and State barriers have been erected that are preventing the proliferation of its use. Removing these barriers is of great importance to MeadWestvaco, the paper and forest products industry, and all IECA member companies.

MeadWestvaco is a leader in the use of CHP technologies producing over 70 percent of the power requirements at our domestic pulp and paper mills through co-generation. But there is much more potential for its use in the U.S. overall.

A December 2008 Department of Energy report states that there is a potential for CHP to supply up to 20 percent of the U.S. electricity generating capacity by 2030. In doing so, we could avoid 60 percent of the projected increases in carbon dioxide emissions over this time period. This is a huge opportunity for the Nation to become more energy efficient, to reduce greenhouse gas emissions at a reasonable cost. It would also increase jobs and the competitiveness of the manufacturing sector.

We have identified nine barriers and solutions for each in the written testimony. Working in the energy area for over 20 years, I have personal knowledge that the barriers are real, and my company has experienced firsthand the increased costs, delays, project cancellations, and significant opportunity lost from the imposition of these policies.

The first category of barriers includes those associated with an overall Federal regulatory policy direction which does not sufficiently distinguish CHP from merchant powerplants. This is seen in the interconnection rule for facilities larger than 20 megawatts where CHP units have to go through the same costly, lengthy, and complicated process that merchant generators do if they seek full compensation for the power they may want to sell to the grid.

In addition, under the rules' deliverability standard, a new CHP unit is not allowed to compete on price with the incumbent for the use of the grid even though the incumbent may be a less energy efficient generator. A manufacturer or developer that wants to locate a CHP unit at a manufacturing site which is in a transmission-constrained area would be required to finance transmission upgrades as part of the interconnection process.

The second category covers more traditional financial barriers that include the basic cost of the CHP facility, the lack of a long-term price certainty in wholesale markets which makes it difficult to finance projects, tax incentives that are limited to facilities of 50 megawatts and smaller, the threat of exit fees, life-of-contract demand ratchets in industrial tariffs, and prohibitive costs for stand-by and maintenance power needed by the manufacturer.

Other barriers on our list include environmental permitting and new burdensome reporting requirements instituted by the Electric Reliability Organization for interconnected facilities that make sales to the grid.

A new looming barrier is climate change legislation that does not recognize the environmental benefits of CHP as compared to an electric utility powerplant alternative.

It is vitally important that these barriers be addressed. We look forward to working with members of the subcommittee on these issues. I would be pleased to take any questions you may have. Thank you.

[The prepared statement of Ms. Kowalczyk follows:]

PREPARED STATEMENT OF IRENE A. KOWALCZYK, DIRECTOR, ENERGY POLICY AND SUPPLY, MEADWESTVACO CORPORATION, GLEN ALLEN, VA

Barriers to Increased use of Cogeneration, Distributed Generation and Recycled Energy

MeadWestvaco Corporation (MWV) is a global leader in packaging and packaging solutions with $6.6 billion in revenue and 22,000 employees worldwide. We currently have facilities in 30 countries and serve the world's largest consumer product brands with packaging in healthcare and pharmaceuticals; cosmetics and personal care; food and beverage; home and garden; and media and entertainment. Our other leading businesses include Consumer & Office Products, and Specialty Chemicals, which uses byproducts of the papermaking process to develop solutions for air and water purification, asphalt performance additives, and emulsifiers and dispersants.

MWV is part of the forest products industry which is the leading producer and user of renewable biomass energy, and is a member of American Forest and Paper (AF&PA), the national trade association for the industry. Much of my testimony today is based on my experience as a member and chair of the AF&PA Energy Committee, leading the industry's advocacy efforts on energy policy.

Sixty-five percent of the total energy used at AF&PA member paper and wood products facilities is generated onsite from carbonneutral biomass. The industry also is a leader in highly efficient cogeneration of electric power (also called Combined Heat and Power or CHP), much of it from biomass, both for internal use and for sale to the power grid. Since 1972, AF&PA member pulp and paper mills have decreased the use of fossil fuels and purchased energy per ton of product by 56%. From 2004 to 2006, they reduced their use of fossil fuels and purchased energy per ton of production by 9%. This was mostly achieved by extensive use of CHP technologies. In 2006, AF&PA member pulp and paper mills produced more than 28.5 million megawatt hours of electricity. This represents one third of the industrial CHPgenerated energy in the U.S.

Co-generation or CHP is the sequential or simultaneous generation of electricity and thermal energy (usually in the form of steam) from the same fuel for use at a host facility that makes both electricity and another useful product or service requiring heat. With CHP, relatively little heat value of fuel is wasted compared to conventional generating processes. This is the basis for the savings. In general, CHP is about twice as efficient at using fuel compared to the standard electricity generating technology. Because CHP systems use less fuel, they produce fewer emissions to the air; so there is also less particulate, Carbon Dioxide (CO_2), sulphur oxides (SO_2), nitrogen oxides (NO_X) and other pollution emitted than in utility systems using the same fuels. Adding CHP power generation units widely dispersed throughout the electrical grid also improves system reliability in that the electrical system is less dependent upon any single generation unit. Since the power which is cogenerated is typically used locally, investments needed in transmission infrastructure are reduced and electric transmission and distribution line losses are also lower, often as much as 7%.

MWV's three domestic mills co-generated 1.86 million megawatt hours of power in 2007 which represents almost 70 percent of these mills' total power requirements. Use of CHP saves millions of dollars in energy costs annually and reduces our CO_2 emissions significantly compared to purchasing all of our power from the local utility. In addition, since most of the fuel used in our cogeneration facilities is biomassbased, our CO_2 emission reductions are further enhanced.

The Department of Energy (DOE) stated in a report issued in December 2008 that thencurrent use of CHP nationwide avoids more than 1.9 Quadrillion Btu of fuel consumption and 248 million metric tons of CO_2 emissions compared to traditional separate production of electricity and heat. This CO_2 reduction is the equivalent of removing more than 45 million cars from the road. According to the DOE, CHP was almost 9% of US power capacity in 2007. In the same report, the DOE states that if CHP were to supply up to 20% of U.S. electricity generating capacity by 2030 (241 GW of CHP out of 1,204 GW total), the projected increases in CO_2 emissions would be cut by 60%.

The many benefits and value provided by CHP was recognized with the passage of the Public Utility Regulatory Policy Act (PURPA) in 1978. PURPA sought to encourage cogeneration and small power production as well as renewable power production by guaranteeing that these facilities would not be discriminated against when connecting to the electrical grid, by ensuring that they could get supplemental, backup and maintenance power at just and reasonable rates and by requiring that utilities purchase power from facilities that met PURPA qualifications at the cost the utilities avoided by not having to build additional power plants or purchase power from the wholesale market. For 20 years since the law's passage in most parts of the country the increased use of CHP and power generation from renewable energy sources was fostered by implementation of these basic principles. Over that time period cogeneration and power production from renewable resources increased from 4% to nearly 9% of US power generation.

In certain parts of the country there was continued resistance to implementing the federal law. As a result, policies were put in place which continued to provide preferential treatment for utilities' power plant build options. For example, in some jurisdictions there were no provisions for mandatory competitive bidding, utilities' true avoided costs were not transparent and the tariffs established by the state regulator for PURPA-qualified facilities to sell power to the local utility did not provide the assurances needed to secure financing for CHP facilities. Developers asserting their federal PURPA rights at the state level incurred significant litigation costs. Many ultimately gave up and developed their projects in more CHP friendly parts of the country where they could also find the steam hosts they needed to build these PURPA-based projects.

In some states the Public Utility Commissions required the costs of purchase power agreements to flow through the fuel adjustment mechanism at cost. Since the utilities involved were not afforded an opportunity to earn a return on the capacity component of these agreements, they resisted entering into PURPA based purchased power agreements. In contrast, utilities are typically given an opportunity to earn a return on the equity invested under the self build option. Therefore this regulatory treatment created a bias against CHP.

Over the last 10 years, regulatory barriers, often in the name of improving the reliability of the nation's power grid, have negatively affected the growth in CHP. The problem was further exacerbated with the passage of the Energy Policy Act (EPAct) of 2005, which substantially revised PURPA. Under the Federal Energy Regulation Commission's (FERC) interpretation of this law, utilities are not required to demonstrate that their markets were functionally competitive before being relieved of their PURPA mandatory purchase obligation. In effect, the utility simply has to be a member of an established Regional Transmission Organization (RTO) or Independent System Operator (ISO) to be automatically exempt.

In its interpretation of the law, the FERC also placed the burden on CHP generators to prove discrimination in the implementation of an Open Access Transmission Tariff (OATT). An OATT is a FERC approved tariff designed to provide nondiscriminatory open access to the transmission system. Under the FERC OATT, all nonutility users of the grid are to be afforded access under the same terms and conditions as utility users. However, in practice, nonutility users have not received nondiscriminatory access as was intended by the FERC. This is primarily because of utilities' right to preserve transmission capacity for future native load.

In mid-December 2008, the D.C. Circuit Court affirmed the FERC's decision. These interpretations are important because they effectively end the purchase obligations for utilities in a large part of the nation. Although existing contracts were not affected, any qualified facility seeking a new arrangement for expanded or additional capacity may find itself with little leverage in negotiating with utilities. They will have to interconnect with the RTO or ISO and deal with the barriers associated with doing so, discussed below.

Barrier #1: Interconnection Standards Remain a Deterrent to CHP Entry

Interconnection policy has broad implications for competitive entry of cogenerators and other forms of distributed generation. FERC has finalized new generation interconnection rules for both small facilities with capacity less than 20 MW and for larger generators with capacity greater than 20 MW. These rules represent an improvement in many areas of interconnection policy. The FERC standards are the default only if the RTO or ISO has not set its own unique standard. The following RTOs or ISOs have been developed in the U.S.: ERCOT ISO, California ISO, SPP RTO, MISO RTO, PJM RTO, NY ISO and NE ISO.

A significant barrier to entry for cogenerators is a concept called "deliverability" which requires generators and CHP seeking to interconnect to potentially have to finance transmission facility upgrades. This standard requires that generators have to prove that their output is deliverable to load and if it is not, then they have to finance the transmission upgrades necessary to make the power deliverable. This approach is generally incompatible with competitive entry into ISO/RTO markets.

The FERC interconnection rule defines a dual approach with two new types of interconnection services: "Energy Only Service" and "Network Resource Service." The standard is based upon the PJM model of interconnection. Facilities that qualify as a Network Resource Service are guaranteed a much higher price for their electric power than Energy Only Service. To obtain Network Resource Service status in PJM for example, facilities must go through an extensive three prong interconnection process and pay the cost of upgrading the transmission system if the studies show that such upgrades are necessary for the power to be "deliverable" to load. Even though this money is refunded with interest over time in bill credits for transmission service, facilities seeking to interconnect must put up this money up-front to fulfill the interconnection requirements. Facilities can only participate in PJM's auctions to receive a capacity payment from the administered capacity market if they are fairly far along in the interconnection process toward becoming a Network Resource.

The "deliverability" standard provides for the reduced price paid to "Energy Only Service" providers which do not become "Network Resource Service" providers. This is because these new entrants are treated as the "marginal unit" which must be worked into the mix and be capable of running simultaneously without disturbing the incumbent units' "right" to run. This preference of Network Resource Service units over Energy Only Service units is used even when the Energy Only Service units can provide power at a lower price than Network Resource Service units. Under FERC's dual Energy/Network interconnection standard, the concept of "deliverability" limits competition from new entrants who wish to displace higher cost incumbents from the transmission system.

Another aspect of meeting the "deliverability" standard for CHP facilities in some RTOs is that they must demonstrate that their power output is "deliverable" to the market. In the impact study phase of the interconnection process the RTO assesses what upgrades are necessary to deliver power from the CHP to the market without the industrial load being present. It is virtually impossible for the CHP to be able to deliver this power if the industrial site to which it is intrinsically tied is assumed to not exist. Unlike merchant generators, larger scale CHP facilities cannot be sited to minimize interconnection costs posed by the deliverability standard as they usually colocate at the already existing industrial site. As a result, CHP plants oftentimes limit themselves to making sales into the nonfirm energy market (Energy Service Only—lower price) in order to avoid the burden imposed by the deliverability standard.

Barrier #1: Solution

It should not be the responsibility of the new entrant offering a lower price designed to displace the incumbent's facility for the benefit of consumers to build transmission facilities in order to compete for the same load. In a purely physical sense, any unit connected reliably to the electric grid and capable of delivering energy to any load is "deliverable" to that load. The interconnection standards which rely on the "deliverability" concept are overly burdensome, but they need not be so. This is evidenced by the approach taken by the New York and New England ISOs that adopted a non-discriminatory standard as a regional variation to FERC's rule. This standard, known as the Minimum Interconnection Standard, maximizes competitive entry to the grid. In RTOs that have adopted this alternative standard, any unit which is interconnected to the grid in a fashion which preserves the reliability, stability and existing transfer capacity of the grid (without expanding the grid) is entitled to compete in both the 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 the basis of price to determine which unit gets dispatched. The current FERC and PJM concept of "deliverability" in the interconnection standards should be abandoned. The Minimum Interconnection Standard used in the New York RTO and New England ISO should be adopted by the FERC as the default and by all the RTOs and ISOs in the nation.

Barrier #2: Discriminatory Treatment of Behind the Meter CHP

RTOs and ISOs have repeatedly attempted to interfere with CHP in the area of "Behind the Meter" pricing. "Behind the Meter" generation refers to electricity generated on site 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 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. They try to charge for transmission, ancillary services and administrative fees based upon the total electrical consumption of a manufacturing facility, rather than the "net" amount actually taken from the grid. This cost allocation scheme is known as "Gross Load" pricing.

Gross load pricing failed in the PJM RTO when an equitable settlement was reached between PJM and Behind the Meter generators, most of which were owners of CHP installations. However this issue continues to be raised in the context of a resource adequacy cases and in other proceedings. In a rehearing of a MISO case (Dkt. ER08-394-001), the FERC reversed itself and decided to disallow the netting of Behind the Meter generation from gross load for purposes of utility native load forecasting and for calculations of planning reserve margin requirements. This illustrates that owners of Behind the Meter CHP facilities must remain continually vigilant in their advocacy efforts on this issue as the challenges to the appropriate treatment of Behind the Meter generation is a recurring problem.

Barrier #2: Solution

In order to prevent this issue from being a continual deterrent to increased CHP implementation, legislative language should be developed which would ensure that CHP and distributed generators will not be required to pay for services on a "Gross Load" basis and that services paid for will be based on the "net" amount actually taken from the grid or utility.

Barrier #3: Operational Challenges Faced by CHP in an RTO/ISO Environment

CHP facilities like those operated by the manufacturing industry are different than merchant or utility power plants that only have one purpose which is to produce electricity for sale. While a CHP may elect to sell power into an electrical transmission grid, its primary function is to support the host facility by providing electric power and steam or other useful thermal energy for the manufacturing process. The FERC program to standardize the use of the grid through the development of RTOs and ISOs fails to recognize this important difference.

Generally the operating rules developed by RTOs and ISOs fail to recognize the significant operational differences between cogenerators and merchant generators. This is the case even though the FERC has acknowledged in a California case where the issue was specifically addressed that qualified CHP facilities differ in purpose and operation from traditional generators and that reducing the host facility's control over the curtailment and dispatch of their power could lead to process, safety and health problem for the host facility.

RTOs and ISOs often require that interconnected generators, including onsite CHP, 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 CHP's primary business. This requirement is a significant disincentive for any industrial CHP facility seeking access to the grid.

Barrier #3: Solution

The RTO or ISO cannot accommodate the dynamic requirements of CHP's industrial processes when the first priority of a CHP facility is the provision of steam or heat to the industrial host. The RTOs and ISOs should not mandate that CHP facilities comply with all the operational rules developed for merchant generators listed in their generic tariff provisions and mandated by execution of their operating agreements. Instead, they should increase flexibility of the tariff to allow for the refinement of contract terms to accommodate any particular needs and concerns with respect to the curtailment and dispatch of CHP. This accommodation of CHP is warranted in light of the economic and environmental benefits that accrue from CHP operations.

Barrier #4: Financial Barriers to CHP

CHP 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 a three year maximum forward basis. For example, by the end of May 2009, sellers of capacity on PJM's system will know what they will be paid through May 2013. The lack of long term price certainty, which was afforded by PURPA's mandatory purchase obligation, is a major deterrent to financing the installation of new CHP.

Despite the guidelines provided in PURPA for the design of just and reasonable utility rates for standby and maintenance power needed for CHP facilities, some Public Utility Commissions approved very high rates for these services. This has proven to be a real barrier.

Barrier #4: Solution

Develop a Clean Energy Standard Offer Program (CESOP) as national policy to reduce the barriers to entry for CHP and recycled waste energy facilities. The federal government should require states to offer long term contracts for the purchase of electric power from facilities that utilize waste energy, recycled energy and other clean technology. Under CESOP, state regulators determine the cost of delivering electricity from the best new, electric only power plant that meets environmental standards and then offers long term contracts for clean energy at 80% of that cost. Two different CESOP rate structures are possible depending on whether the power is generated from industrial waste energy or from new CHP that meets the annual efficiency tests. Both structures would ensure that the state obtains clean energy at a cost below what it would pay for power from new coal fired centralized facilities. Utilities would be allowed to earn a return on the capacity provided by the new CESOP facility. The contract term of 20 years would remove the financing problem mentioned above.

Another suggestion for consideration is to provide feedin tariffs to encourage the development of CHP resources. This approach is being used in the European Union as part of their cogeneration directive. A feed-in tariff is an agreement between an electricity generator and a utility whereby the former is paid an agreedupon rate (could be the CESOP rate or another rate set by the regulator) for electricity that is fed back onto the grid. This kind of arrangement can be used to deliver all of the CHP production to the utility or it can be used to deliver the excess electricity produced. The over-arching principle is that it allows for optimization of the CHP facility to ensure maximum efficiency.

All states should be encouraged to review the design of their standby and maintenance rates to ensure that they are consistent with the guidelines provided in PURPA.

Barrier #5: Exit Fees and Life of Contract Demand Ratchets at State Level

In 1996, the Code of Alabama (37-4-30) was amended to allow electric utilities to impose exit fees on industrial customers who seek to serve their power requirements from CHP facilities owned by entities other than themselves (third-party CHP). The argument used to support this practice was that utilities incurred "stranded costs" due to the industrial seeking more energy efficient options for their steam and power supply. The utilities argued that recovering these "stranded costs" through an exit fee on those who obtain power from such CHP facilities and who leave the utility system is justified since it protects those customers who remain on the system. Many thirdparty CHP facilities which should have been built in Alabama to serve industrial load since 1996 were not built because the threat of an exit fee significantly affected the economics of the project. This law, which has not been repealed, protects the utility's franchise, continues to sanction a highly discriminatory practice and prolongs inefficiency in the generation of power.

Some utilities throughout the country have life of contract demand ratchets in their tariffs for large industrial customers. These serve as a deterrent to increased installation of CHP since the industrial customer must pay for up to 75% of the demand listed in its contract regardless of whether it takes the power or not. Many customers faced with the cost of this potential demand ratchet wait to install or upgrade their CHP facilities until after the initial term of their contract has expired. Often the contract can then be cancelled during an annual rollover period to minimize costs incurred from this demand ratchet. Sometimes, if the customer will continue to buy any power, the utility has the discretion under their tariff to decide whether it will allow the contract to be cancelled. The customer may have to file a complaint with the state PUC if the utility is unwilling to voluntarily reduce the contract demand level.

Barrier #5: Solution

It is a national imperative to require State Public Utility Commissions to remove tariff language which can be a barrier to increased use of CHP. State legislatures should also be encouraged to review their Code to ensure that any laws still on their books that are a barrier to increased use of CHP are repealed as soon as possible. Federal legislative language should encourage states to not tolerate any discriminatory practices in either their Rules and Regulations or in the Code.

Barrier #6: Environmental Permitting

The lengthy and extensive process to secure environmental permitting for CHP is a barrier to entry. The DOE has stated that 31 states regulate emissions based on heat input levels (lb/MMBtu). Such approaches do not recognize or encourage the higher efficiency or the pollution prevention benefits offered by CHP. In addition, major new emission sources are required to meet New Source Review (NSR) requirements to obtain operating and construction permits. NSR sets emission rates for criteria pollutants and requires installation of the Best Available Control Technology (BACT). New sources are also required to offset existing emissions in nonattainment areas. As a result of these environmental deterrents, CHP facilities are often times not installed because even though they may represent marginal improvements, they do not achieve BACT or sufficient offsets are not available in these nonattainment areas for the new facility to get built.

Barrier #6: Solution

Expedited and streamlined permitting procedures for CHP facilities, which will increase the energy efficiency of an industrial operation, are greatly needed.

The DOE has rightly pointed out that output based approaches to regulation that include both the thermal and electrical output of a CHP process can recognize the higher efficiency and environmental benefits of CHP. Although some states, primarily in the northwest, have adopted output based approaches, the majority of the states have not done so. Legislation could encourage states to move in that direction. Provisions should be made to allow CHP facilities to get permitted even if they are not necessarily achieving BACT as some improvement is better than no improvement at all.

Barrier #7: Treatment of Existing and New CHP in Proposed Climate Change Legislation

Another potential deterrent to the expansion of CHP looming on the horizon is in the treatment of existing and new CHP facilities in any greenhouse gas reduction program. All climate change cap and trade proposals presented so far provide inadequate recognition of, and incentives for, CHP in the manufacturing sector. Although producing power via CHP uses energy more efficiently than producing utility power, direct (onsite) emissions of a facility using CHP will typically be higher than if the facility only produced thermal energy and purchased all electricity from offsite. Since the benefit of a CHP system is reducing indirect emissions (i.e., from purchased electricity), a capandtrade program where compliance is measured solely on reducing direct emissions will not adequately account for the benefits of CHP. It is critical that the efficiency gains associated with CHP systems of all sizes be properly recognized in a capandtrade system. Otherwise industry with untapped cogeneration potential will be hesitant to install new CHP because they will have to secure allowances to emit from the new facility while not receiving any credit for the reduced power consumption.

Another barrier will potentially emerge when developing the methodology for allocating free allowances in any cap and trade program. The two most commonly discussed methodologies for allocating free allowances are based on either: 1. historic direct emissions (not including purchased power) or 2. a percentage of a product benchmark within that industry sector.

The problem with the historical emissions approach is that it does not consider the superior energy efficiency attributes of existing CHP and treats such facilities similarly to a utility plant. The historical emissions approach imposes a cost on polluters but provides no incentive to existing clean energy sources such as CHP. Emissions based approaches also do not provide an incentive mechanism as its basic construct for the nation to become as energy efficient as possible through CHP and distributed generation resources. This will be a major deterrent to new CHP being developed.

The problem with providing a percentage of a product benchmark within the industry is that it does not provide any credit for any industry that has, in order to remain competitive in a global marketplace, already taken great measures in becoming as energy efficient as possible through the extensive use of CHP. As a result, their specific product benchmark will be lower, reflective of the extent to which this industry has embraced CHP or other energy efficiency technologies over the years. This is especially true for the pulp and paper industry that has an exemplary track record in having embraced and installed CHP technologies. Such industry should be awarded for that activity, not compared to its own industry benchmark that by its very construct already reflects that activity.

Barrier #7: Solution

Climate change policies should recognize the benefits of, and promote investment in, CHP by providing credit for the avoided emissions associated with an existing and new CHP units. If a cap and trade program is established, special provisions will need to be made for CHP systems as current cap and trade approaches provide no credit for the energy efficiency provided by such systems. Any climate change proposal should promote investment in CHP by providing credit for the avoided emissions associated with a CHP unit. The accounting credit for energy efficiency increases should be equal to the difference in CO_2 emissions generated by a CHP system as compared to the equivalent CO_2 emissions associated with generation of electricity by utility companies and the separate onsite generation of thermal energy. Each facility may then deduct those CO_2 emissions savings associated with that CHP unit from emissions regulated under a GHG regulatory program. Any surplus credits generated by a facility shall be eligible for an emissions reduction credit.

Another option to consider as an alternative to the emissions based approach for allocation of allowances is an output based approach which is based on efficient energy production instead of efficient product production. One such output based approach would award each electric producer, including a CHP facility, with initial allowances of 0.62 metric tons of CO_2 emissions per delivered megawatthour of electricity. In addition, each thermal energy producer would be provided with an initial allowance of 0.44 metric tons of CO_2 emissions per delivered megawatthour of thermal energy. These allowances reflect the 2007 average national emissions for electric and thermal. The next step requires every plant that generates heat and or power to obtain allowances equal to its CO_2 emissions. This encourages all actions that lower greenhouse gas emissions per unit of useful output and penalizes above average pollution per unit of output, thereby unleashing innovation and creativity. It also would measure an industry based on its efficient energy production and award those industries that have historically already undertaken those initiatives.

However, should an emissions based approach be ultimately adopted, a solution to removing the deterrent to increased CHP would be, as discussed above, to establish a mechanism for transferring emissions allocations from a utility, which would see reduced emissions from the installation of CHP, to a CHP system, which would increase its direct emissions.

Barrier #8: Lack of Incentives for Large Scale CHP

There is some interest in promoting CHP in climate change proposals which have been filed to date but unfortunately they only focus on small CHP facilities. At the present time there are no incentives whatsoever for large scale CHP facilities, yet these facilities face the same barriers to entry as do the smaller CHP.

Recognizing the benefits of distributed generation, the American Clean Energy and Security Act discussion draft renewable energy provisions provide that distributed generation facilities receive three renewable energy credits (RECs) for each megawatt hour of renewable electricity they generate. This legislation defines distributed generation facility as a facility that: generates renewable electricity “other than by means of combustion”; “primarily serves 1 or more electricity consumers at or near the facility site”; and can be no larger than two megawatts in capacity.

The Energy Efficiency Resource Standard (EERS) provisions in the discussion draft, like other EERS bills, define CHP to exclude facilities with net wholesale sales of electricity exceeding 50 percent of the total annual electric generation by the facility. This disincentive for CHP is inconsistent with the EERS policy objectives. All the customer facility savings from electricity generated by CHP facilities should qualify under any EERS.

The recent revision of tax policy to provide incentives for any CHP up to 50 MW in size is a positive development but such incentives should not be size limited. There are many potential cogeneration facilities at industrial sites which are not eligible for the investment tax credit because they need to be larger than 50 MW to capture economies of scale.

There are state practices that are discriminatory towards CHP in the provision of natural gas delivery services to CHP facilities.

Barrier #8: Solution

As a member of an industry that is a leader in the use of CHP, we believe that our significant investment in CHP should be rewarded. Specifically, any climate change or energy bill should provide extra renewable energy credits (REC) for electricity generated through CHP, regardless of the size of the generation facility. It is inconsistent with the policy goals of an RES to limit extra RECs only to small facilities, as larger facilities provide the same environmental and greenhouse gas reduction benefits as do smaller facilities. The strained definition of distributed generation facility is unnecessary and should not be adopted.

The 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.

All CHP should be eligible for an investment tax credit, regardless of size.

It may also be appropriate to establish targets for CHP and recycled energy that increase capacity installation and operation. In particular, CHP and recycled energy should be declared acceptable to meet at least half of the requirements in any adopted policy requiring a percentage of power purchased for resale by utilities to come from renewable or energyefficient sources of electric generation.

Incentives should be provided for states that adopt, for jurisdictional utilities, a natural gas delivery tariff that provides delivery to CHP facilities at rates for transmission and distribution service no less advantageous than the rate at which natural gas is delivered to any other gasfired electric generator. This has already been implemented in much of New York State.

Barrier #9: Burdensome Reporting Requirements

Another deterrent related to CHP interconnection can be found in the EPAct of 2005 in the establishment of the Electric Reliability Organization (ERO) to ensure the reliability of the electric power transmission grid. All interconnected generators, including qualified CHP facilities must become members of their regional electric reliability organization if they want to sell any power to the grid. They must agree to extensive reporting and other requirements imposed by that reliability organization. Compliance with these new mandatory requirements is time consuming and expensive and poses another barrier to CHP connecting to the grid. These additional reporting requirements being imposed on CHP result from the general policy direction of not distinguishing between CHP and merchant type facilities.

Barrier #9: Solution

CHP and other distributed generation facilities making net sales to the grid that are incidental to their main purpose should be exempt from these new reporting requirements. Legislative language should be developed to provide such exemptions.

Senator CANTWELL. Thank you, Ms. Kowalczyk. Again, thank you to all the witnesses for being here today and for your work in this area. I believe—I know the chairman of the full committee believes—this is a very important policy area and we appreciate you being here to have this discussion.

One thing that I wanted to just start off with because you all talked about the importance of net metering in general and the need for standards. Obviously, we thought in the 2005 bill that we took a good whack at this, and it did result in States adopting various policies. But obviously, we are not getting the full results that we would like to see. So I wanted to talk about the various things that are out there and the differences between them.

I know people have proposed model interconnection standards. Obviously, NARUC has in the Interstate Renewable Electricity Counsel, which I know, Mr. Cook, you are involved with this. What are the differences between those standards that would be potentially a larger national standard? What could we do to take the best of each of these to create a national interconnection standard? Whoever wants to start with that.

Mr. COOK. Thank you, Madam Chairman.

I would say the difference between the model rules that NARUC has and the model rules that IREC has—first, NARUC's model rules are focused just on interconnection. It is important to distinguish the interconnection rules are the technical rules that allow a generator to interact with the grid. Net metering is the tariff arrangement, the economic arrangement, that that generator would have with their local utility. Correct me if I am wrong, but I do not believe NARUC has model net metering rules. They have model interconnection rules, but no model net metering rules.

I think that is part of what has hampered some of the States. EPAct 2005 also did not really have a specified model saying these are the elements that make net metering function, these are the things that you look for in a good net metering rule that will allow customers of all classes, residents, small businesses, large businesses, even industrial customers to utilize, for example, onsite solar systems to offset part of their electricity.

So there are very few models out there. IREC may be unique in having the only model net metering rules in place.

With respect to the interconnection rules, NARUC was the first to come out with model interconnection rules. They actually predated FERC Order 2006. It was good rules at the time, but like with FERC Order 2006, there have been a lot of improvements that have occurred. Lots of debate has gone on in the States where consensus amongst all the people, small generators, utilities, the staffs of the local commissions, have made improvements on the data base or the information that was available both at the time that NARUC came up with their model and FERC came up with their model.

So those improvements, I think, are enhancements that streamline and further aggrandize the ability for small generators to be interconnected with the grid, and I think those improvements should be embodied in a national model whether coming from the Senate and Congress or whether developed at FERC through the direction of Congress to develop the model.

Senator CANTWELL. Mr. Brown, did you want to comment?

Mr. BROWN. Yes. I think he makes an important distinction between interconnection requirements and net metering. Interconnection requirements are really about safety and reliability of the system. If you have power going into the system, no matter what the fuel source that gets it there, there are dangers associated with that if you do not properly interconnect the system. Net metering is a program to try to, I think, in some ways jump start technologies to remove institutional barriers that are out there.

I think where you have seen the difference in the systems again may have to do with where the State sits. Where you have, for example, restructured electricity markets, there is a pretty clear distinction between the costs that are associated with commodities, the fuel used to make the electricity, and the delivery system, paying for the system that gets the electricity there. Where you have got more vertically integrated utilities, that distinction is less clear.

How you set up net metering may, therefore, be dependent upon whether you are in a restructured State or not, and you might want to set it up different in those two circumstances. One size may not fill all in that case.

But interconnection—I think we need to be careful. We really cannot use interconnection requirements to try to jump start technologies. What we have to make sure of completely is that they do not stand in the way of those technologies being able to get in the system, and that was the case for many years. A lot of the utility interconnection requirements were used as much to discourage new technologies as they were to ensure safe and reliable service.

Senator CANTWELL. How about you, Mr. Weiss? Do you think we should update the FERC Order 2006, so make that the standard?

Mr. WEISS. I think he was absolutely right that it is a different situation in deregulated environments and fully regulated environments.

Where we do most of our work is in the mid-Atlantic area in the PJM area, and I think if we could get to a point where the rates are fully decoupled and the utilities are neutral to how much power is being consumed and where it is being consumed, it will really help.

Interconnection is most definitely a safety issue and a local system issue, and if the distributor generator owner can get the full value for its electricity through net metering, it will most certainly jump start many installations and technologies.

Senator CANTWELL. Ms. Kowalczyk, did you want to comment on that?

Ms. KOWALCZYK. We do not particularly have a point of view with regard to the net metering for the smaller facilities.

However, I would make a point with regard to the revenue decoupling discussion. Manufacturers are not in favor of the revenue decoupling type schemes because we need to see the savings in our electricity bills in order to implement energy efficiency projects, be they co-generation or anything else. If you are decoupling the revenues from the sales of the utility, it will take away that incentive for the manufacturer to implement those energy efficiency projects because you are paying basically the same rate that you would have otherwise paid, and that is a real problem.

Senator CANTWELL. What do you think the California experience has been? Are you familiar with that?

Ms. KOWALCZYK. Somewhat. They do not have an awful lot of manufacturers in California. We have seen a reduction in the manufacturing base in California. I think that the electricity costs are very high in California. They may not have seen the huge increases in the demands out there because of the decoupling schemes, but their costs are high.

Senator CANTWELL. We will get back to that in a minute. I want to let my colleague, Senator Bingaman, ask questions.

The CHAIRMAN. Thank you very much.

On the interconnection, first of all, I guess I am hearing a fairly consistent message from folks that there really is no logical reason for not having uniform interconnection standards across the country. Is that right, or does somebody have an argument as to why there should be differences in the interconnection standards from State to State to State?

Mr. BROWN. I am not going to try to pretend to be an expert about all 50 State systems, but I do know—and while we have managed to come up with an interconnection standard in New York, system configurations can differ greatly, for example, between a New York City type system with the underground feeders and Upstate New York, fairly rural in character at certain points. The same rules do not always precisely apply with those differing sort of systems. I would assume that probably is even more true as you get into other systems with very different configurations in the West than we see in the East. It is not saying—we have managed to come up with a single interconnection standard that has worked in New York. Whether that could be applicable everywhere, I do not know.

The CHAIRMAN. Part of the argument that I have always thought made sense for nationwide interconnection standards was that it would simplify the market for companies that are in the business of producing the equipment that is needed to do this kind of thing. If you are a company and you have got to produce a different configured widget for every State, it complicates things and I would think discourages them.

Let me just ask Mr. Kelly. From your perspective, you folks adopted an interconnection standard even for small generators, as I understand it, but it has not been generally adopted. Is that right? You sort of went over this in your testimony, but maybe you could restate what has happened to FERC's efforts to get an interconnection standard adopted for small generators.

Mr. KELLY. We adopted a standard for small generators that was very, very close to the standard recommended by NARUC in the hopes that individual States would adopt something close to that joint model. We have not tracked that States have adopted what standard, but I hear anecdotally—and Chairman Brown may know this slightly better than me—that some States have not adopted any standards and some States have adopted variations on this joint NARUC/FERC standard.

The CHAIRMAN. What would be wrong with Congress coming along and saying, OK, you have got 18 months or 2 years or something to adopt this standard or something comparable in the view of FERC, or the standard that FERC has adopted is hereby applicable?

Mr. KELLY. From a technical point of view, I do not see any difficulty with that.

The CHAIRMAN. Would that accomplish a significant amount if we did that? Mr. Cook, do you think that would be a step forward?

Mr. COOK. Yes, very much so. I will share my experience, having been involved in State interconnection proceedings, some 20-odd State interconnection proceedings. Out of those, one State adopted roughly the FERC language, including if you look at the text of their interconnection rules and standards, it mirrors and borrows heavily from the FERC rule. For whatever the cause or the reasons, States want to go down their own path, and even if they end up at a place that roughly equates to what FERC did in its order, it is difficult for the folks that I represent, the installers and the manufacturers, because they look at it and it is different language. It may be ordered differently. It may look like a different standard even if when you roll back the skin of onion, it is actually the standard.

So very much so it would help to have, to the extent at all possible, standardizing across all the States to have a seamless interconnection standard.

The CHAIRMAN. Now, to what extent, if we did that, if we had a standardized interconnection standard along the lines that FERC has already put out there for consideration, does that solve any of the problems with combined heat and power? Does it address your issues at all, or are we talking apples and kumquats here?

Ms. KOWALCZYK. No. It is a different animal because we are generally looking at the interconnections for the facilities 20 megawatts and larger.

But one thing that perhaps could help is if Congress were to direct the FERC to abandon the deliverability standard that I talked about and instead adopt the minimum interconnection standard that has been successfully used in the New England ISO and the

New York ISO. It would reduce some of the barriers that I have described.

The CHAIRMAN. OK.

Then on net metering, that is sort of a different kettle of fish. Let me try to understand there. It is your position, Mr. Cook, that there is a model net metering statute that ought to be also dealt with the same way, put out there, and everybody is advised to either adopt it or something very similar to it by a certain time, or else it is going to be applicable. Is that your view of how that problem should be fixed?

Mr. COOK. Yes, it is, and I think that would help to address the broader patchwork, frankly, that exists in net metering across the States. There is broader patchwork and differentiation than there is even on interconnection. So I think the Federal guidance there is even more important to do roughly the same as you laid out for interconnection, yes.

The CHAIRMAN. Thank you. My time is up.

Senator CANTWELL. Thank you, Senator Bingaman.

One of the reasons why I think this is so important—I mean, obviously, infusing more intelligence into the electricity grid is just that it will help us in trying to reduce peak power demand as well. According to GAO, 100 hours of annual peak demand, which is just 1 percent of total yearly needs, accounts for 10 to 20 percent of the annual electricity costs.

So to put that into dollars, according to the Brattle Group, even a 5 percent drop in peak demand can yield substantial savings in avoiding generation, transmission, and distribution. So estimated at $3 billion a year or $35 billion over the next 2 decades.

So I wanted to get into a little bit about this issue of how building out a smart grid and distributed generation can help us in peak demand. I know, Mr. Cook, you have had, obviously, experience here dealing with this. Can you explain how distributed generation like solar panels combined with the smart grid helps to lower that peak demand cost?

Mr. COOK. Particularly for solar, solar is what we call in the industry a peak generating technology. That is really by happenstance in that in most utility grids or regional transmission grids, the peak consumption tends to follow sunlight. You do not tend to find areas where peak consumption is, say, at 2 in the morning. Solar generally tracks the demands on that. So it follows the peaks on the system for consumption. There may be shifts. You know, the solar production may peak at 1 or 2 in the afternoon, where the utility peak may be 3 or 4 in the afternoon. But generally, there is a parallel there. So solar technology, by just the nature of the way it generates electricity, tends to offset the peak demands that exist.

The smart meters, I think, go toward trying to reduce people's consumption. As you and I probably do, we do not realize that when we are running lights or a dishwasher or something like that, is it a peak period on the grid? Is every generator that is out there struggling to meet the demand on the grid? I think the concept behind the smart metering is if we can get that information out to customers, perhaps tied with some price signal that says if you can reduce your demand now, if you cannot use electric-consuming equipment, there will be some financial benefit to you as well, people will reduce their consumption during those peak periods and thereby reduce the peak demands which, as you note, are the incredibly costly times to put generation on the grid.

Senator CANTWELL. But by reducing peak demand, we reduce the cost to the ratepayers.

Mr. COOK. Yes. I think that equation probably holds true, and Mr. Kelly might have some more detailed information on that. But it is a very small percentage of the hours that leads to a very large percentage of the total costs that are incurred. So if you can reduce that consumption during those few hours, typically 100 or 200 hours a year, it has a significant impact on reducing the cost of generation. That is because so many generators, in essence, sit idle waiting for that peak to occur and they have to earn all their money during those peak periods because the rest of the 8,500 hours of the year, they are just simply not needed. So if you can get consumers of electricity to say we are not going to use during those critical hours, you can reduce the total costs that are paid for generation substantially.

Senator CANTWELL. Mr. Kelly or Mr. Weiss, did you want to comment on that?

Mr. WEISS. There is a tie-in between solar net metering and smart meters. Smart meters really is the technical way that if we had a smart metering standard where we can measure how much electricity is going out to the grid from a solar project that is behind the meter and how much is going to come in, and they could cancel each other out, which would allow the host customer, the person who owns the solar project, to gain more value.

Net metering, being an economic issue, is a much easier standard to develop and put out there as a goal or as some legislation because it does not have safety issues related to it. It just has economic issues related to it. If you tie in a smart metering standard with a net metering economic benefit, it will undoubtedly create a lot more solar projects.

Senator CANTWELL. Mr. Kelly, did you have a comment on that?

Mr. KELLY. Just to reiterate a couple of points. Shaving the peak demand is important. The Nation has made great strides in doing that over the last few years, and we have plans to make still greater strides in the years ahead. Congress gave FERC some assignments to do that, and we are pursuing it vigorously.

A lot more can be done. I think one way to do that is through net metering.

But I would like to pick up on a point Chairman Brown said because I think it is very important. When you are dealing with interconnection standards, you are dealing with safety. You want to make sure that the standard is not done in such a way that an electrical line worker could get electrocuted because not everything was studied properly and installed correctly. When you are dealing with net metering, the issue is dollars. If you are going to have net metering, what is the appropriate compensation? It is something the States have been dealing with, not FERC to date. But they are two very different issues: safety versus dollars.

Senator CANTWELL. We have had, I think, several hearings that have touched on this in a broader way, obviously, with various panelists. So I am sure we will continue.

But one of the reasons that I think it holds so much promise besides helping drive down the cost on renewables and taking advantage of renewables at non-peak time is that just the combination of all of these things together, distributed generation, smart grid, efficiency, peak demand technologies, could be a huge source of savings for us.

In fact, I am interested in—obviously, we are trying to move energy legislation—what you think the best case scenario would be here for a percentage of power that could be met through these sources. I do not know if anybody wants to take a stab at that. I mean, could we see as much as 30 percent energy in the future by, say, 2030 if we invested wisely in this area?

Mr. BROWN. I think it depends on how wide those words you used mean.

I was going to comment on your last about reducing peak demand. That is obviously a tremendous goal of ours. Right now, the most cost-effective way of reducing peak demand is just through good old-fashioned energy efficiency programs, what we call demand reduction programs where people respond to peaks by reducing their usage.

If you want to combine those sort of traditional energy efficiency programs with renewable programs—in New York, we have already got a goal of trying to reduce our electricity demand by 15 percent by 2015 and having 30 percent of our electricity produced by renewables by 2015. We call that the 45 by 15 program. I think New Jersey has got a 20 by 20, trying just on energy efficiency alone. So I think your 30 percent is very doable if you combine all the potential opportunities that are out there.

That is why we have to be careful, I think, again trying to dictate this specific program or this specific technology is the way to get there because what might work in New York may be very different in Washington or New Mexico or Texas. The resources are different. The systems are different. That is why, I guess, from the States' perspective we say we are trying to achieve very many of the same goals already on the State level. If done wrong, Federal policies could hinder our progress. If done right, it could really, working together, make it happen quicker.

Senator CANTWELL. That is why I think this means it probably is one of the most significant things that we could do because if you are saying you really could achieve 30 percent source from energy efficiency by 2030 by combining all of these things, smart meter technology and distributed generation, then you do use the opportunities that exist within each region. So you are not basically choosing any one region's energy solutions over another. You are implementing the efficiencies into the system and driving down costs to consumers. I do not know anybody else who can come up with 30 percent in that short a period of time.

In the meantime, you actually create a lot of jobs, I would assume, by doing this as well. Obviously, the economic model still needs to be considered.

Mr. Weiss.

Mr. WEISS. Energy efficiency is by far the cheapest way to produce energy. What I mean by that is the energy not produced is going to be cheaper than the energy produced. Over and over, a good energy efficiency program with measured and verified savings will accomplish more in saving peak energy and energy off peak throughout the Nation. It is the least expensive, lowest hanging fruit.

Mr. COOK. I also wanted to weigh in and point out that if you look at the two most aggressive States with the distributed solar program, California and New Jersey, and use their year-over-year growth built into their program, they actually reach 30 percent of their generation from distributed solar by 2030.

Senator CANTWELL. Ms. Kowalczyk, did you have a——

Ms. KOWALCZYK. I would agree with what David had said.

But just back for a minute to this issue of the smart meters, there are just so many parts of the country where we do not have the smart rates that need to be implemented together with the smart meters. If we cannot get the price signal to the actual consumer, then all the smart metering in the world will not be helpful or beneficial.

Senator CANTWELL. I wanted to follow up the California situation. I mean, given what Mr. Cook just said about California, obviously, there are a lot of things that have been going on with California energy prices, not just their adoption of decoupling and moving forward on these technologies. Do you have the specifics about how much that has impacted the cost of energy in California?

Ms. KOWALCZYK. Not specific to California. We do not have facilities there. Sorry.

Senator CANTWELL. OK.

I would like to know a little bit too from the panelists what contribution they think renewable generation sources could play in meeting a Federal standard. So how does a renewable energy credit help support the market and distributed generation especially when it comes to homeowners who want to generate their own electricity? Does anybody have a comment on that?

Mr. COOK. One of the programs with which I am familiar is the New Jersey solar program which provides renewable energy credit or a certificate for every megawatt hour of solar energy produced, and then the New Jersey regulators, the Board of Public Utilities, created a market for that by saying that the people who supply electricity in the State have to include as part of their portfolio a certain percentage which is represented by these credits. So if you are selling electricity in the State, maybe on an annual basis you have to go out and purchase 200 solar credits whether it is an installation like Mr. Weiss explained at a large facility or a homeowner can actually then go out and sell these credits because the market has been developed for those.

I think the last time I checked, in New Jersey they were going for a fairly good price which represented what additional costs it would take to install a solar energy system. That cost comes down each year as the cost of solar installation goes up in New Jersey and the incremental cost to install each of those goes down fairly substantially.

Mr. WEISS. To further demonstrate that, our large solar installation in Atlantic City basically has three revenue components that make the returns work for us. Twenty percent comes from selling the electricity to the host customer at just slightly below retail rates. 40 percent of the value comes from Federal tax credits, and 40 percent of the value comes from the solar rent market.

Senator CANTWELL. Yes, Ms. Kowalczyk.

Ms. KOWALCZYK. With regard to energy efficiency being a part of a renewable standard, we believe there should not be any limitation on the amount of energy efficiency that could participate in any such program. These energy efficiencies should be allowed to compete head to head with renewables.

Senator CANTWELL. I have one last question about baseload because—I will let you off the hook on this one, Mr. Kelly, but Chairman Wellinghoff was recently quoted as saying baseload capacity is going to be anachronism to where we are going, and in so many words that smart grid and distributed generation would allow us to reshape with renewables so that we will not need fossil fuel.

So do you agree that smart and more distributed generation could forgo the historical requirements for some level of baseload power?

Mr. BROWN. I have had the occasion to see Chairman Wellinghoff three times since then. So I have heard him explain his comments three times. I think when you put them into the context of what he was saying, it is much more understandable to be saying.

What he was saying is, one, there is tremendous possibility for energy efficiency that we just discussed, real savings there.

Two, there is an incredible amount of potential for all our renewable resources from off-shore wind, on-land wind, to solar, to biomass, all these various technologies. So we could meet a lot of our demand using energy efficiency and renewables.

But I think the third point that got lost in his quote a little bit was if we can have—right now what we have are powerplants that intentionally are designed to move up and down to meet the instantaneous changes in load. If we could use the demand side, if we could use load to balance, if there was enough sophistication in the system that load could actually respond in real time, all of our appliances, icemakers could shut off or shut on depending on the time of the day and the price. You know, a silly example, but there could be chips in a lot of different appliances that actually allow you to do that from a demand side. Then you might not need those sort of baseload facilities, the standard facilities that we usually think of, the coal, the nuclear facilities, to do that.

But I think Chairman Wellinghoff would also explain we are long way off from that, and we better not put all our eggs in that basket. We better continue the research on coal, nuclear, and in the near term, we are not going to be eliminating baseload plants.

So I hope I explained what I heard his view. I agree with that viewpoint with the “ifs” set up, if the efficiency, if the renewables, if the demand side, then maybe we can change the paradigm in the future.

Mr. WEISS. We do a lot of energy performance contracts in large Federal facilities, in hospitals all over the east coast. We do a lot of load following. I mean, the technology is not that far away so that you could reduce demand. It is done in the commercial and industrial sector for years, and I think it could be applied residentially.

Senator CANTWELL. Again, just before we close out, there is nothing about the introduction of more smart grid technology or distributed generation that really gives preference over one energy source or another.

Mr. BROWN. I think they all need to be part of the solution. What we face as State regulators——

Senator CANTWELL. But there is no source that takes inherent advantage of the fact that we would create more of a national infrastructure here.

Mr. BROWN. I think it is energy efficiency that benefits the most from the smart grid, probably more so than anything, but also our ability to incorporate technologies like solar and intermittent technologies like wind. The smarter and more information there is in the grid, the easier it will be to have instead of 8 percent of our resources be wind, to have 25 percent of our resources be wind, instead of 2 percent of our resources be solar, to have 12 percent of our resources be solar. The intermittency of those technologies can be dealt better with. So it helps all of the goals I think. It is just very expensive.

Mr. WEISS. Smart meters and net metering creates opportunities. It creates opportunities for all renewable energy and energy efficiency and the control of energy. I think that is where we are going to get the most benefit in the next 10 years, next decade.

Senator CANTWELL. Thank you. I want to thank all the panelists, again, for being here today. We will keep the record open so if my colleagues have further questions, they can submit those and, obviously, get responses from you. But we appreciate very much you being here today and your testimony on this important subject.

The Subcommittee on Energy is adjourned.

[Whereupon, at 3:36 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

RESPONSE OF GARRY A. BROWN TO QUESTION FROM SENATOR STABENOW

Question 1. I understand the generation of heat and power accounts for more than two-thirds of U.S. fossil CO_2 emissions. I also understand the efficiency of generating electricity has not improved from its dismal 33 percent level since the time of President Eisenhower. Can you describe some of the policy barriers to more efficient power generation, specifically distributed generation?

Answer. The efficiency of producing electricity from conventional large base-loaded steam-turbine driven sources is fundamentally limited by the thermodynamic limitations. There are actually several separate energy conversions at play in the conventional production of electricity, each having its own conversion efficiency limitations. Fuel is burned in a furnace producing heat, which is converted in a boiler to high-pressure steam, which is then passed through a steam-turbine producing rotating mechanical energy that spins the generator producing electricity. Approximately two-thirds of the fuel consumed in producing electricity by this method is lost in the process, hence the maximum overall electricity conversion efficiency of about 33 percent.[1] Efficiency improvement opportunities are available, however, and have been utilized by re-capturing some of the otherwise 'lost heat' from the conventional conversion process and either using it directly for onsite thermal energy purposes or recirculation through a heat-recovery boiler, thereby producing additional steam and electricity. Recapture of the 'lost heat' generally increases overall conversion efficiencies to the 50 percent-65 percent range. For these higher efficient technologies to be utilized as distributed generators by individual customers, however, the customers must have an inherent onsite opportunity to economically utilize the waste heat. Since many customers do not have a readily adaptable use for the waste heat, distributed combined heat and power (CHP) facilities will not likely be a cost-effective investment option for customers in most cases. And, where there is an existing onsite use for the waste heat, economics usually dictate that the optimal CHP system be designed to satisfy the site's waste heat requirements, which doesn't necessarily result in an electricity production component that is perfectly matched with the customer's onsite electricity requirements.

Another factor limiting the number of more efficient distributed CHP installations is fuel prices. CHP units typically require the use of natural gas as their primary fuel source. While this enables in a more environmentally compatible outcome than the combustion of other, less expensive, fossil fuels it also tends to offset some of the economic gains otherwise achieved from the improved conversion efficiency.

Hence, despite the improved economics of CHP as compared to straight conventional electricity production technologies, the bottom line CHP costs of producing the electricity on site are not always competitive with electricity prices available from the host utility's electric grid. Optimization of the operation of a distributed CHP facility, such that it minimizes the customer's overall cost serving onsite electric and thermal requirements, requires a real time knowledge and awareness of coincident utility service prices.

Maintaining interconnected access to the utility grid, therefore, both enhances the customer's opportunity for minimizing the overall cost of satisfying onsite energy requirements and assures a back-up and supplemental supply should the customer's

[1] The addition of environmental controls that limit the level of effluents emitted during the fuel combustion process, effectively reduce overall conversion efficiencies below 33%.

distributed generator fail to operate. This also obviates the need to install redundant onsite distributed generator capacity at individual sites to maintain service reliability.

RESPONSES OF GARRY A. BROWN TO QUESTIONS FROM SENATOR RISCH

Question 2. We know that advanced meters allow consumers to be more aware of how they use energy and how much energy costs at a particular time. Would allowing the installation of advanced meters also facilitate the adoption of distributed generation?

Answer. Installation of advanced meters will facilitate the transfer of more detailed system pricing and operational data (information) between the utility and its customers, and as such, likely enhance the integrated operation of the utility's delivery system with individual distributed generators dispersed within that delivery system. The development of more accurate, time differentiated, electric delivery and commodity pricing structures where appropriate, however, will best enable the full benefits of advanced meters to be realized by both DG and non-DG customers.

Question 3. Even with distributed generation, the local distribution company must maintain the lines that allow for the two-way flow of energy between the distributed generation entity and the grid. They also must assure that there is back-up energy available in the event that the distributed generation goes down or under-produces. Should we devise a financial scheme that allows the local distribution company to meet these responsibilities without having to shift the cost to the consumer?

Answer. NARUC does not believe that it is appropriate or beneficial for Congress to set retail rate design or retail rate policy. While we agree that there needs to be regulatory action to allocate theses costs, it should be a tailored decision made at the State level and not a single federal standard or scheme legislated by Congress. The financial scheme, however, should be the development of utility tariff rates that more accurately and appropriately charge customers for the services they use, regardless of what they chose to do behind-the-meter in order to improve the efficiency or reduce the cost of meeting their energy requirements. Ultimate across-the-board implementation of alternative delivery rate structures stabilizes the local distribution company's ability to recover the costs needed to meet its service obligations and obviates the need to invoke what are in effect discounts for some customers at the expense of other customers.

An alternative utility delivery service rate structure, Standby Delivery Rates, is presently in place at the New York State utilities. These rates were designed for the specific purpose of assuring the utilities continued recovery of legitimate unavoidable fixed delivery service costs from those customers operating their own onsite (distributed) generating facilities, thereby mitigating the extent to which the recovery of such unavoidable delivery service costs get shifted to other ratepayers. These rates are presently applicable only for those customers electing to install onsite distributed generators.

Question 4. EPACT 05 attempted to address some of the impediments to the deployment of distributed energy resources by requiring state public utility commissions and certain "non-regulated" utilities to consider standards for net metering and interconnection. Does NARUC believe that Congress needs to legislate a national model, or go even further and legislate national standards?

Answer. No. I would suggest implementation details, and the tariffs specifying such details be left to the States. It's neither necessary nor appropriate to address these details at a national level. Approximately 35 States currently have interconnection standards and/or rules and approximately 42 States currently have net metering standards and/or rules. As I mentioned in my oral remarks and answers to questions during the hearing, there are fundamental differences between the delivery systems across the nation (i.e. rural and urban.)

Question 5. Mr. Cook's testimony discusses the need to remove several existing barriers to distributed generation. In your testimony you describe a three-year process to develop model interconnection standards in an attempt to produce a document that would remove or alleviate most of the access issues and fit the regulatory systems in the vast majority of the United States. What was the result of this process? What barriers still exist, in your opinion?

Answer. As I testified, once the barriers were determined, NARUC's members started a three-year process to develop model interconnection standards for small generation resources in an attempt to produce a document that would remove or alleviate most of the access issues and fit the regulatory systems in the vast majority of the States.

This process, as well as the Federal Energy Regulatory Commission (FERC) order 2006 process, which had extensive State involvement and coordination, greatly improved the promise of new and cleaner distributed generation technologies—like fuel cells, micro-turbines, distributed wind machines, and photovoltaics—by working to significantly reduce market barriers that existed due to inconsistent and outdated grid interconnection standards. The end result of these processes was the issuance by FERC of a Small Generator Interconnection Procedures.

This procedure is a model for ISOs and/or States to use in the development of interconnection procedures. While interconnection procedures have improved greatly in recent years, we still have to be vigilant that they are not causing barriers and look to improve the procedures whenever possible. I believe that State regulators are in the best position to monitor how interconnection procedures are working and make the needed revisions consistent with the conditions on the local distribution systems.

RESPONSES OF IRENE KOWALCZYK TO QUESTIONS FROM SENATOR STABENOW

Question 1. I understand many paper-product companies generate electricity, often using their own waste products or capturing and recycling their waste heat. Such distributed generation seems to be saving you money, cutting pollution, and generating power at much lower cost than to buy the electricity from new centralized power plants. Do you ever generate more power than you actually use? How much more could you save if power markets were open and generators were not restricted in terms of whom they could sell power to apart from utilities? What if you were allowed to sell your electricity under long-term contracts to a variety of possible buyers?

Answer. Paper-product companies are leaders in the use of cogeneration technologies and these facilities often produce more power than what is needed to serve the facilities' loads. In regulated markets such facilities have traditionally sold excess power to their local utilities at avoided cost under PURPA-based agreements. As a result of the FERC's interpretation of revisions to PURPA in the EPAct of 2005, utilities that have joined an RTO or ISO and are located in regulated states are no longer required to purchase output from co-generators. In deregulated markets these facilities will often sell energy to the wholesale market directly but they will not sell capacity because of the onerous interconnection standards discussed in answers to several of the following questions.

Typically an excess power situation is caused by a process disruption. An example is where there is a break of the paper on a paper machine, shutting down the machine and almost instantaneously reducing the mill's demand for steam and immediately increasing the steam header pressure. The steam producing power boilers, especially biomass based boilers prevalent in our industry, cannot react fast enough to reduce their output so the high header pressure is relieved by having the steam flow to the turbine generator. Under these upset conditions more steam flows through the turbine to its condenser and as a result more power is produced which must be delivered either to serve plant load, the local or the wholesale grid.

Over the past 10 years many paper machines have been shut down due to competitiveness issues, but the energy producing infrastructure is still intact at the site. These mills which previously had cogeneration systems which were well balanced between their power and steam requirements now find themselves with excess turbine generator capacity. In order to utilize these assets fully, a buyer for the power generated in excess of plant loads must be found.

The economies of scale particular to a specific site should dictate the size of cogeneration systems. Frequently, however, the systems are designed to not produce excess power in order to avoid the difficult and cumbersome issues related to selling excess power, be it to the local utility or to the wholesale market. This results in cogeneration systems that are sub-optimally designed and therefore their costs of installation and operation are higher than they otherwise would be. If excess power more easily could be sold to buyers under long term contracts, then the cogeneration systems could be more optimally designed, could generate more renewable, highly efficient energy, and could displace more fossil-fuel based energy. In regulated markets this is virtually impossible as the utilities will ensure no transmission capacity is available to move the cogenerator's power to the buyer, through their ability to reserve transmission capacity for future native load. This is the case even in areas of the country where the determination of available transmission capacity is made by an independent entity.

When it comes to sales at the wholesale level, in RTOs and ISOs which have established separate energy and capacity markets, we estimate that for every 10 MW of excess power a cogeneration facility sells as "energy only" into those markets today, the facility could have obtained an estimated $365K in additional revenue per year in payments for the capacity associated with that energy sale. This is value usually forgone by the seller.

Question 2. Your testimony and comments at the hearing demonstrated that while energy-intensive industries and the average family consumer would both benefit from types of distributed generation, there are differences between industrial and residential energy needs in a "smart grid" electricity framework. You mentioned that smart meters will only work where electricity rates are "smart rates," meaning rates that adjust depending on how much is consumed within a billing period, rather than a flat average rate, because the consumer would need the price signal to prompt an adjustment in consumption. You also mentioned at a different point that manufacturers are opposed to decoupling (a rate design where utilities are paid based on how well they meet their customers' energy service needs, rather than the predominant design which focuses on commodity sales) because they need the price signal of lower energy bills to implement energy efficiency measures and reduce consumption. How can distributed generation and net metering be promoted without decoupling?

Answer. Rates with blocks adjust charges based on how much is consumed within a billing period. For example, a typical declining block rate will charge a customer a higher rate for the first increment of power purchased in any month and a lower rate for all incremental consumption above that first block of power. Declining block rate design has been the norm as an option for large power consumers for a long time. "Smart rates" do not adjust based on how much is consumed within a billing period but rather adjust based on the utility's costs of generating and purchasing electricity at the wholesale level at a particular point in time. Smart rates can change as often as hourly and typically they would change the rate more frequently than current time-of-use rates which change by season and usually two times in a day.

Decoupling is usually promoted as a means of encouraging utilities to become engaged in promoting energy efficiency but it is really just a revenue guarantee for utilities. Paying uneconomic "rents" to utility shareholders to prevent them from taking actions harmful to society (like discouraging CHP, distributed generation or demand response) should not become accepted public policy. Every consumer will pay the price for having our nation become more energy efficient and less dependent on foreign energy sources. Utilities and their shareholders should not be insulated from sharing in the sacrifices and adjustments required of every other business in these times. A fair opportunity for the utility to recover costs and losses should be the standard.

One of the largest impediments to efficient deployment of CHP and distributed generation is not utility disincentives, but incorrect rate designs that intentionally load uneconomic costs on CHP and distributed generation. Current rate designs often incorporate allocation mechanisms that include charges in volumetric rates which should be in the fixed cost component of the rate. As a result the utility loses a disproportionate amount of revenue when a large customer paying a volumetric rate reduces or eliminates consumption. If rates were not improperly weighted towards volumetric recovery of costs, but were instead properly designed to recover fixed costs through a fixed charge and variable costs through usage charges, the dislocation would be far less. Proper rate design removes utility disincentives towards CHP and distributed generation.

In order for manufacturers to finance and install CHP systems, they must be able to show savings in power costs to justify the investment. If the utilities' revenues are decoupled from commodity sales then manufacturers lose the main incentive for increasing efficiency—the prospect of lower energy bills. For example a new, more efficient boiler at a paper mill would consume less energy and cost less to run. However since decoupling would compensate the paper mill's utility for lost revenue, that same mill would end up paying a higher rate despite using less energy.

As mentioned above, revenue decoupling is not needed to promote CHP or distributed generation if proper rate designs are implemented. As far as net metering of distributed generation is concerned, the power which is net metered to the utility reduces the utilities' need to either purchase power or run their least efficient generating unit, depending on which resource is on the margin when net metered power enters the grid. Net metering of power onto the grid affects the variable or purchased power costs incurred by the utility but does not affect the utility's ability to recover fixed costs.

If the public policy goal is to promote increased utilization of CHP and distributed generation, the utilities should adjust their revenue expectations accordingly and not be kept immune from the impacts of these policy decisions through revenue decoupling mechanisms. The utilities should be required to contribute their fair share in achieving energy security and climate change goals and not be carved out of making the sacrifices that all consumers will have to make.

An alternative is to remove administration of energy efficiency programs like the installation of CHP and distributed generation from utilities and vest them in an independent agency. Several states, such as New York and Vermont have already adopted this approach for some or all energy efficiency and DSM programs. External administration of programs does not remove the need for properly designed rates, but it does eliminate the fear that utilities will not be supportive of these programs.

Question 3. Your testimony says that FERC policy on interconnection standards make it difficult for companies to build CHP facilities. Please explain why the FERC policy is a problem.

Answer. The FERC Order on interconnection for large generators was issued in 2003, the barrier raised related to interconnection has been a concern for industry for quite some time. The question posed is best answered by sharing the attached whitepaper prepared by Don Sipe, outside counsel to AF&PA Energy Resources Committee. The whitepaper shows that the FERC policy of requiring a deliverability standard in the interconnection rule, especially as applied to a competitive market, promotes overbuilding of transmission and discourages new entry.

WHITEPAPER ATTACHMENT

INTERCONNECTION POLICY—THE ISSUE OF "DELIVERABILITY"

INTRODUCTION

Interconnection Policy has broad implications for competitive entry, Resource Adequacy, QF viability, Transmission Pricing Policy (including Participant Funding) and Demand Response. Poor or discriminatory Interconnection Policies restrict entry, increase the cost of interconnection, decrease power supplies thereby driving up prices, and limit demand response opportunities. For all of these reasons, in both RTO and non-RTO regions, influencing these policies is often the most direct way to lower costs and increase competitive opportunities.

FERC has recently finalized new generation interconnection rules. These new rules represent a substantial improvement in many areas. In one area, however, the rules perpetuate a potentially discriminatory interconnection standard based on a concept (adopted from PJM) called "deliverability". The deliverability concept is generally incompatible with competitive entry into ISO/RTO markets. New York and New England RTOs had adopted a different, non-discriminatory standard as a "regional variation" on FERC's rule. That standard, known as the Minimum Interconnection Standard, maximizes competitive entry to the grid. Since passage of the Rule in 2007, FERC has required ISO-NE to move back to a dual interconnection standard with a "deliverability" component.

In non-RTO markets, FERC's new Interconnection Policy represents a significant step forward in relation to the largely ad hoc rules which prevailed prior to issuance of the Order. Under the new rules, utilities like Southern and Entergy are required to interconnect IPPs or other potentially competing generation "on the same basis as they connect their own units". The Order defines two new types of interconnection service based upon the PJM model of interconnection: "Energy Only Service" and "Network Resource Service". This dual standard allows some flexibility in markets without competitive opportunities like those of the Southeast. But in markets based on competitive principles like ISO's and RTO's, the dual standard is not only unnecessary, but discriminatory and anti-competitive.

The problems presented by this policy have become even more glaring with recent developments. One of the main purposes of Renewable Portfolio requirements and energy efficiency legislation is to reduce consumption and displace existing fossil fuel units with newer, less polluting renewable resources. Yet, current interconnection policy forbids displacement and instead requires new renewable entrants to build transmission as if both they and the older units they will displace have to keep running to serve load. This is illogical, anti-competitive environmentally harmful and economically wasteful. It discourages CHP and renewable development.

STATEMENT OF THE PROBLEM

Transmission systems are built to serve load, not the aggregate amount of generation on the system. A typical transmission system will have more generation connected to it than the total amount of load which is available to take service from that generation. This is necessitated both by reserve requirements and by competitive principles. Without some surplus supply, competition between suppliers is ineffectual because all suppliers are needed just to serve load reliably.

In regions without competition, where utilities engage in Vertically Integrated Resource Planning, there is a more careful match between utility generation and the expected load. With the exception of reserve requirements, utilities do not routinely build more generation than needed to serve expected load. he situation becomes more complicated, however, under competition. In order to have competition, there must be a certain amount of surplus generation. Particularly in a bid-based market with LMP, market power concerns would be overwhelming if generation supply "just matched" the normal, vertically integrated utility planning criteria of load plus reserves.

The two types of system; competition and vertical integration; also affect transmission planning. In a vertically integrated system it is much easier to plan transmission based on the expected flow from particular generation resources to specific load. Under competition, however, generation may come from a variety of directions or sources to serve load depending upon the prices offered. Under either system, however, in order to take service from a particular generator, the generator must be able to "deliver" to the load. This seems like a very straightforward requirement. However, utilities in PJM (which provided the model for FERC's interconnection policy) have turned the concept of "deliverability" into a tool to favor and protect incumbents against competition from new entrants in the capacity markets.[1]

Under FERC's dual Energy/Network interconnection standard, the concept of "deliverability" limits competition in the capacity markets from new entrants who wish to displace higher cost incumbents from the transmission system. Under the "Energy Standard" of interconnection, a unit can interconnect in a fashion which meets all the reliability criteria for safe operation, but will only be allowed to compete in the non-firm energy market. Such a unit cannot be counted as a capacity resource. To play in the capacity markets, the unit must be connected under the "Network Resource" standard which requires a study to prove that output from the unit is "deliverable".

By contrast, prior to FERC's ruling, in New England and New York, any unit interconnected to the grid in a fashion which preserves the reliability stability and existing transfer capacity of the grid (without expanding the grid) was entitled to compete in both the capacity and energy markets. If there was not enough capacity on the transmission system to "deliver" the output from both the new and existing units, then the units were forced to compete on the basis of price to see who gets chosen as a capacity provider. Whoever wins the bidding war is dispatched and is obviously "deliverable" to the load. If the system needs to be expanded so that more generation in total can be delivered from, say, a low cost to a high cost area, that decision is made by the Independent System Operator, and the expansion is made part of the transmission plan. New entrants are not forced to expand the system so incumbents who they have underbid can continue to "deliver" to load who would rather buy from the new, cheaper source anyway.[2] This pro-competitive notion of deliverability, however, is not the concept embodied in the FERC Network Interconnection Policy. Under the Network Resource Standard, deliverability means insuring enough transmission is built to protect incumbents from being displaced.

[1] Again, we should contrast here the situation in non-competitive markets where insuring deliverability may force the hand of the local utility to build and fund upgrades which would have the effect of expanding its system. Although the deliverability concept described and criticized hereafter might still be used by these utilities to the disadvantage of new entrants, it is a double edged sword for a utility like Southern or Entergy who has been extremely successful in closing down system expansion or any other development necessary to allow competition.

[2] For a thorough discussion and critique of the FERC's dual interconnection standard and problems it creates for competitive markets, see Motion to Intervene, Protest and Comments of the Industrial Energy Consumer Group, Docket No. ER04-433-000 which can be made available upon request if there is interest in a more in-depth discussion.

THE CONCEPT OF DELIVERABILITY AS MISUSED BY THE PJM STANDARD

In a purely physical sense, any unit connected reliably to the electric grid and capable of delivering energy to any load can deliver both energy and capacity with no further modification of the electrical system. This physical idea of deliverablity, however, is not the test applied under the FERC Network Resource Standard.

To illustrate, we offer a simplified example. The diagram* below represents a system composed of a single transmission line connected to a 100 MW load. At the other end of the line, interconnected to the line in an electrically indistinguishable fashion, are two 100 MW generators.

The load has the option of choosing either of the generators to serve it. Whichever one it chooses, the system is capable of delivering the output (both capacity and energy) of the generator to the load. While it is true that, both generators cannot run simultaneously (for one thing there isn't enough load to absorb them both) it is obviously true that as a matter of electrical engineering, either could run (or each could run at ½ output) to serve the load. It is the load which, in a competitive market, would generally get to decide what combination of generation serves it. Under the "deliverability" standard of FERCs Interconnection Policy, however, that is not the test (at least with regard to capacity). Rather, the test for deliverability will produce the anomalous result that, even though both generators are absolutely equivalent from an electrical point of view, one of them could be considered "deliverable" and one of them might not be. The choice will not be made based on any economic or engineering rationale, but simply on the basis of who was there "first".

Under the deliverability test in FERC's Rule, a new unit must be connected so that "the aggregate of generation can be delivered to the aggregate of the load". Obviously, this is a highly imprecise standard which, depending on the details and assumptions in the study, can be used to discriminate in a variety of ways. For instance, in any existing system, it is obviously not possible to deliver all (i.e. "the aggregate") of the generation simultaneously to load, since there is always more generation than load. It is always some subset of generation that is serving load. The usual manner of applying the deliverability standard is to first choose the "preferred" subset of incumbent generation which is dispatched to serve load. After this preference has been established, the new entrant is treated as the "marginal unit" which must somehow be worked into the mix and be capable of running simultaneously without "disturbing" the preferred units' "right" to run at any level they choose. Despite all the convolutions of the study protocol, this is simply a matter of favoring the incumbent units and treating new entrants as if they are the "marginal" unit.

In our simple example, if A were the incumbent, the study would dispatch A at 100MW, and then see if there were any room for B (the new entrant). Since A and B can't both run, B is not "deliverable" and is not allowed to compete for the loads business as a capacity resource.

DELIVERABILITY TO OR FROM A CONSTRAINED REGION

Deliverability can be used by incumbents as an excuse to create a "straw that broke the camel's back" argument which requires the last new entrant to fund major transmission upgrades to relieve constraints which the incumbents have neglected to remedy in the past. For instance, going back to our simple model of two identical 100 MW generators ("A" and "B") connected to a 100 MW line. Presume that on the end of the line there is 200 MW of load, but there is still only 100 MW of transfer capability. It is true that if Generator B comes on line, it is not possible to deliver any additional MW to the load at the other end without an upgrade. However, there can still be significant benefits (to at least 100 MW of the 200 MW load) if B is offering a substantially lower capacity or energy price. However, in order to protect incumbents, the deliverability test will be structured such that B will not be considered deliverable because there are already 100 MW of "network resource" (i.e. unit A) on line and 100 MW is all that can be delivered over the line. Thus, unit B will face a major interface expansion in order to be deliverable to the 200 MW load even though he could underbid

* Graphic has been retained in subcommittee files.

the incumbent and deliver both capacity and energy at a lower cost by displacing him.

The argument usually advanced for this type of discrimination is that "it is sending the wrong signal to the Generator" to allow it to locate in a place where it does not increase the total capacity available to load. This, of course, ignores the fact that Generator A will be insulated from competition if the incumbent utility doesn't want to build enough transmission to serve load in the constrained pocket. We would argue that the correct "signal" to the Generator is to allow it to compete for the 100 MW of transmission capacity. If it is unsuccessful in competing to displace the incumbent unit, it has made a bad business decision, but that is its own risk. Further, if a new unit truly wishes to provide additional service it can always request and pay for an upgrade. If a new entrant succeeds in displacing the incumbent and the incumbent still wishes to deliver power, it is free to expand its system to do so. It should not be the responsibility of a new entrant offering a lower price or a cleaner resource to correct the failures of transmission system planning of the incumbent utility before it is allowed to compete for load in the capacity market.

For all of these reasons, competitive principles require variations to the FERC's dual Interconnection Standard in any region where competition is the prevailing model. The Minimum Interconnection Standard once approved in New England and New York can serve as the basis for a nondiscriminatory, pro-competitive approach which will lower barriers to entry and increase competition. Interconnection under that standard should permit a new unit to compete as both a capacity and energy resource. Further, even where competition is not the norm, the purpose and goals of any Renewable Portfolio Standard will be frustrated if interconnection policy is not revised to allow new cleaner units to displace older, fossil fired units on the transmission system.

Question 4. We will be addressing climate change legislation again this year and we need cost effective ideas to help us significantly reduce greenhouse gas emissions. I can see that CHP technology offers a tremendous opportunity to help the environment and help our manufacturing industries increase competitiveness and jobs. How could CHP facilities receive recognition for their efficiency and how would you do so under cap and trade?

Answer. Although producing power via CHP uses energy more efficiently than producing utility power, direct (onsite) emissions of a facility using CHP will typically be higher than if the facility only produced thermal energy and purchased all electricity from off-site. Since the benefit of a CHP system is reducing indirect emissions (i.e., from purchased electricity), a cap-and-trade program where compliance is measured solely on reducing direct emissions will not adequately account for the benefits of CHP. It is critical that the efficiency gains associated with CHP systems be properly recognized in a cap-and-trade system.

Climate change policies should recognize the benefits of, and promote investment in, CHP by providing credit for the avoided emissions associated with a CHP unit. The credit should be equal to the difference in CO_2 emissions generated by a CHP system as compared to the equivalent CO_2 emissions associated with generation of electricity by utility companies and the separate on-site generation of thermal energy.

Given the range of configurations of CHP systems and fuel combinations used, each facility would calculate the emissions savings provided by their CHP system according to an established standardized methodology. Each facility may then deduct those CO_2 emissions savings associated with that CHP unit from regulated emissions under a GHG regulatory program. After subtracting CHP savings credits from the facility's regulated (direct) emissions, any surplus credits generated by a facility shall be eligible for an emissions reduction credit in any carbon market created by the system.

To illustrate the impact of CHP on GHG emissions and energy consumption of a hypothetical 1000 air dry ton (adt) per day integrated Kraft pulp mill, it was assumed that the mill consumes 7,000,000 GJ of steam and 400,000 megawatt-hours (MWh) of electricity per year. It was further assumed that the boiler-based CHP system was designed to satisfy the mill's steam demand, with CHP-generated power offsetting about half of the needed electricity with the rest purchased from the grid.

TABLE 1.—ANNUAL GHG EMISSIONS AND TOTAL ENERGY (SAMPLE P&P MILL) WITH AND WITHOUT CHP

	With CHP (Wood/Oil Boiler)	Without CHP	Difference (impact of CHP)
Direct emissions (onsite, tonne CO_2 eq.)	363,000	328,000	+35,000
Indirect emissions (offsite, tonne CO_2 eq.)	147,000	270,000	-123,000
Total emissions (sum onsite plus offsite, tonne CO_2 eq.)	510,000	598,000	-88,000
Total fuel energy (sum onsite plus offsite, TJ HHV)	12,800	13,500	-772

From the information presented in Table 1 it is obvious that, although direct GHG emissions increase upon employing CHP, total emissions decrease to a greater extent. Total fuel consumption (onsite plus offsite) also decreases. The total emissions savings from use of this CHP system amount to 88,000 metric tonnes CO_2 eq. per year. The method proposed to eliminate CHP disincentives in GHG cap and trade programs would be to allow the facility operating the CHP system to deduct this amount from its direct emissions (compliance obligation).

AF&PA has developed the following potential legislative language based on H.R. 2454 "The American Clean Energy and Security Act" which would encourage the use of Combined Heat and Power Systems to Reduce GHGs.

"(5) INDUSTRIAL STATIONARY SOURCES.—For a covered entity described in section 700(12)(E), (F), or (G), 1 emission allowance for each ton of carbon dioxide equivalent of greenhouse gas that such covered entity emitted in the previous calendar year, excluding emissions resulting from the use of—

"(A) petroleum-based or coal-based liquid or gaseous fuel;
"(B) natural gas liquid;
"(C) renewable biomass;
"(D) petroleum coke; or
"(E) hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, nitrogen trifluoride, or any other fluorinated gas that is a greenhouse gas purchased for use at that covered entity.

(F)combined heat and power systems in accordance with section (F)1

1) EMISSIONS SAVINGS DEDUCTION FOR COMBINED HEAT AND POWER (CHP) SYSTEMS—combined heat and power greenhouse gas emissions savings shall be calculated for each CHP system according to an established standardized methodology which takes into account an individual CHP system's configuration and fuel use. Each CHP system will deduct from their total direct emissions compliance obligation the greenhouse gas emissions savings calculated as the difference in CO_2 emissions generated by a CHP system compared to the equivalent CO_2 emissions associated with generation of electricity by a utility and the separate on-site generation of thermal energy. Any surplus credits generated by a facility shall be eligible for an emissions reduction credit.

Question 5. In your testimony, you say that "exit fees" are a barrier for manufacturing to build CHP facilities. Would you explain what exit fees are and why they are a barrier?

Answer. An exit fee is a charge that can be assessed to a manufacturer that chooses more energy efficient options for their steam and power supply that would reduce electricity demand. The local utility may charge the customer the non-fuel component of the utility power cost for some specified period of time. Exit fees are a barrier because the cost of this charge or simply the threat of such a charge adds massive costs to a potential buyer of the project's electric output. The higher costs affect the viability of the project even before it gets off the drawing board. The net effect of exit fees is the reduction in the potential pool of buyers for the project's power output.

Question 6. In Michigan we have lots of industries that would be ideal places to utilize Combined Heat and Power. Refining, and the production of metals, glass, ethanol, chemicals, cement, pulp and paper, and food processing could all ideally operate at lower cost and reduced emissions with effective CHP systems. As one example, Guardian Industries is a Michigan-based company that produces flat glass in large furnaces that use 1.5 billion cubic feet of natural gas annually in each of their 8 production lines around the country. Since the furnaces operate at 2,900 degrees

Fahrenheit, a lot of heat has typically gone up the stack. I know that Guardian recently rebuilt a furnace at a plant of theirs and are in the process of installing equipment to use that lost heat for generating electricity. This should reduce the plant's electricity demand from the utility by a little over 10%. Most CHP incentives support using waste heat after that heat is first used to generate electricity. Would S.989 [introduced by Sen. Menendez on May 6] support harnessing waste heat that is first used for a different purpose, such as melting sand in glass production?

Answer. S. 989 clearly encompasses the harnessing of waste heat that is first used for industrial purposes, such as melting sand in glass production. Although the bill provides for net metering of such generating facilities, the bill contains no significant incentives to promote projects using waste heat. These projects require financial incentives such as investment tax credits and grants due to the high capital cost. Although the size limitation of 10 MW may not be an issue for the glass production industry, it is a major concern to other manufacturers, such as those in the business of calcined petroleum coke production or steel production, that have huge potential to utilize their waste heat. Most of the opportunity in manufacturing to use waste heat and CHP would be in facilities greater than 10 MW so this bill does not address their concerns at all. In addition, S. 989 also provides for the removal of existing barriers to the installation of CHP systems potentially for use in industrial parks but unfortunately the 10 MW limitation will remain a deterrent to many such facilities being built because the limit on size is too low.

The bill states that backup and standby rates should be based on "actual cost". This generic term may become subject to varied interpretations by the states as what are costs should be included in backup and standby rates. Some PUCs may decide to include utility lost revenue in "actual costs" for standby service. Due to the lack of specificity, this language is not really an improvement over the original language included in the PURPA law of 1978 that required standby rates to be designed to a "just and reasonable" standard. Implementation of the original PURPA language over the past 20—30 years has shown that what is just and reasonable to one party may be onerous to another. PUCs have been generally receptive to utility arguments that it is just and reasonable for standby rates to reflect full retail contract demand costs.

The vague language in S. 989 will enable utilities to argue that they incur the full retail rate as the "actual cost" and the barriers to increased use of CHP will not be reduced, as intended. Therefore additional guidance should be provided in the bill so that standby rates are designed based on quantifiable metrics reflective of the benefits of CHP. Consideration should be given to the fact that standby service is needed when a customer's power plant sustains a process disruption or forced outage which is unlikely to occur coincident with the utility's peak periods. Such an approach would support the case that CHP should have lower, not higher standby and backup rates. One way to achieve this in S. 989 would be to specify the percentages of utility generation and transmission revenue requirements which should be attributable to and used for the design of backup and standby rates. More progressive states have found that just and reasonable standby and backup rates can be developed by assigning 15 to 20% of the per unit costs of providing generation and transmission service. The proposal for the design of standby rtes in S. 989 can be improved by substituting these percentages as a proxy for the term "actual costs".

RESPONSES OF IRENE KOWALCZYK TO QUESTIONS FROM SENATOR RISCH

Question 7. I was surprised that your testimony made no mention of the Industrial Energy Efficiency provisions enacted by Congress in the 2007 Energy Independence and Security Act. In that Act, we created a recoverable waste inventory program within EPA, along with a grants program, and directed the states to consider standards for sales of excess power. How have these provisions assisted the Combined Heat and Power (CHP) industry?

Answer. EPA has not yet issued the proposed rule which will provide criteria for facilities to be included in the inventory, so we have no experience with its actual implementation.

Fellow IECA members have pointed out a concern with the wording of the provisions which will limit its ability to enhance the use of CHP and waste heat recovery systems. EISA 2007 says that a waste heat capture project will not be listed if the project was developed for the primary purpose of making sales of excess electric power. This limits applicability for those manufacturers with waste heat stacks on existing plants who are stranded from a steam host as they have no support for energy capture. A mandated purchase is the most important aspect of any stranded waste heat project as electric power export is the only practical outlet for the energy.

Many manufacturers seek developers to install energy efficiency projects on their premises and the manufacturer purchases energy commodities from the project through supply contracts. In regulated states the developer cannot sell power to the retail customer so the only outlet is to sell power to the utility. Therefore the language in the bill limits developers from entering this business entirely in regulated states. As a result the well intended provisions of the bill will do little to reverse the nation's trend toward continued energy inefficiency where wasted heat is concerned.

Question 8. You have identified a number of barriers to the CHP industry. Has your industry filed any complaints with FERC? If not, why not? If so, what were the results of your efforts?

Answer. The paper industry has been extremely active at FERC in arguing for better interconnection standards. The original case in New England, Bucksport,[1] was filed by a Cogen project which was being denied entrance to the grid because of the deliverability standard then incorporated in New England's interconnection standard. The paper mill at issue, the then Champion Mill in Bucksport, Maine, successfully litigated at FERC and won an improved interconnection standard known as the Minimum Interconnection Standard. That Standard spurred a huge growth in interconnected resources in New England.

The Minimum Interconnection Standard which we advocate, was used successfully for several years in both New England and New York, but came under increasing pressure from system planners, large utilities, and incumbent generator interests who recognized it as a threat to their incumbent status. The Minimum Interconnection Standard allows new entrants to 1) come on to the transmission system in a fashion which preserves the reliability, stability and existing transfer capability of the system and thereafter 2) to compete on the basis of price with all other units to serve load. This is the proper model for a competitive market which assumes that more efficient competitors will "displace" less efficient competitors from the transmission system.

An industrial trade group in New England (which included paper companies) intervened and filed extensive comments in FERC's Interconnection Rulemaking, attempting to preserve the Minimum interconnection Standard in New England and make it the law of the land. However, because of the entrenched interests of utilities and incumbent generators, and the preferences of system operators who find truly competitive markets difficult to manage on a central planning basis, the Minimum Interconnection Standard in New England and elsewhere was eroded by continuing pressure to re-establish deliverability rules. The current standard, even in New England, erases many of the competitive gains achieved under previous litigation.

Finally, in the context of FERC's recent ANOPR on Competition in Organized Markets, AF&PA filed extensive comments on the deliverability issue, explaining the damage done to competition generally by the rule. Prior to filing these comments, AF&PA held several informal meetings with FERC Staff and representatives of PJM, explaining our concerns and discussing the details of the issue with PJM system planners. The FERC did not act upon AF&PA recommendation to eliminate deliverability in its final Rule.

While over-building the transmission system in this way makes it very easy for system operators to plan, it makes no more sense than forcing every new trucking company who wants to compete with existing firms to build separate lanes on the interstate before they are allowed to offer freight service at a lower cost. In addition, there are new imperatives now that make a transition back to a more competitive interconnection process even more vital. There is a recognized need to displace existing, less-environmentally friendly units with new CHP and renewable technologies that will lower emissions. Putting competitive and financial barriers in front of these new projects that are intended to displace existing, less-environmentally friendly units, does not make sense. We do not need to expand the system to allow all the old dirty units to continue to run when competitors with cleaner, newer and more efficient units are coming on line to displace them.

Question 9. You testified that one barrier to CHP seeking to interconnect is that you may have to pay to finance transmission facility upgrades. Why should your industry be exempt from such payments? Aren't you benefitting by being able to put your power on an electric transmission line?

Answer. It is not a question of whether or not a CHP facility seeking to interconnect should have to finance facilities needed to interconnect, but rather how much transmission is needed to do this. A CHP facility should not be required to finance more facilities than are needed to connect the CHP facility in a manner

[1] Champion International Corporation and Bucksport Energy, L.L.C. v. ISO-New England, Inc., New England Power Pool, and Central Maine Power Company, 85 FERC ¶ 61,142 (1998).

which preserves the reliability, transfer capability and stability of the grid. Current FERC policy often mandates that CHP facilities do more than this before they are allowed to compete in capacity markets. Current FERC rules require that they finance facility upgrades sufficient to keep incumbent generators free from competition for use of the transmission system.

If Congress intends to encourage the use of CHP as an alternative to less-efficient or more environmentally harmful fossil fuel facilities, it will be wasteful for CHP facilities to have to fund transmission upgrades so that, existing, less environmentally friendly facilities, can continue to run at their accustomed output even after new CHP units come on to displace them. If FERC persists in this policy, then CHP will not be a viable replacement for existing less-environmentally friendly units because of the added unnecessary transmission costs. Secondly, CHP units that are built to displace fossil fired units will have built wasteful duplicative transmission facilities that are not needed once that displacement occurs.

Clearly, if CHP begins to serve a large segment of load currently served by existing units (which is the intent of Congress), and then existing less-environmentally friendly resources can, and hopefully will be retired. This means that they will not need to have transmission available to serve them because the load will be taking service from renewable or distributed resources instead. Regardless of how much generation is built, the country only needs enough transmission to serve the load that is on the system. Congress is trying to encourage CHP and other renewable technologies to displace existing less-environmentally friendly units in order to reduce carbon emissions. No one benefits by building more transmission than necessary to serve load in order to preserve the “deliverability” of old fossil fired units we hopefully will no longer need. The correct result is to allow CHP to “displace” older, less-environmentally friendly units on the transmission system, not to duplicate or expand transmission facilities beyond the needs of the load to be served.

Therefore, CHP and other renewable or distributed units should be required to build only the transmission capacity which is necessary to connect them reliably in a fashion which preserves the existing transfer capability and stability of the system. They should not be required, as under current deliverability standards, to build more transmission than is necessary to accomplish this purpose.

Question 10. You advocate for Congress to require states to offer long term contracts for the purchase of CHP power. Isn’t this matter more appropriately argued at the state level, where there is responsibility for retail sales?

Answer. It is up to Congress to set national energy policy. The strength of the state review system is in keeping costs down, and so states should definitely have a role in determining which renewable contracts should be signed and with whom. But absent Congressional direction, the political process will make it extremely difficult for states to abandon existing less environmentally preferable coal fired and other units in favor of available renewable and distributed technologies. The easy answer for states, politically, is usually to stand pat. In the past that may have been an acceptable strategy. But climate change and the national security implications of our dependence upon foreign oil have combined to render reliance upon state discretion a less effective means to achieve national objectives. Congress needs to set policy that requires the financial underpinning necessary to achieve a significant penetration of renewable and distributed generation into state portfolios is available.

Question 11. You identify securing environmental permitting for CHP as a barrier to entry. How can you possibly advocate for such a broad exemption, particularly when CHP is often located in rural areas?

Answer. The written testimony speaks of expedited or streamlined permitting procedures, but not necessarily exemptions to environmental permitting. Facilities engaged in CHP understand that regulatory structures must be in place to ensure that ambient air quality standards are protected and that appropriate emissions controls are installed and operated.

CHP projects typically result in improved efficiency, which can result in additional electrical production for the same amount of fuel input or else result in reductions in fuel consumption. Both of these types of changes result in lower emissions. However, due to current regulatory structures many of these changes trigger NSR permitting which is generally a very cumbersome process. It should be noted that certain reforms have taken place that have eased this situation a bit, such as the allowance of “actual-to projected actual” emissions accounting, but additional measures could be taken. It can take from 6 months to 24 months to obtain permits for construction and process modifications. This serves as a deterrent to moving these projects forward to market. The current permitting structure can also require Best Available Control Technology (BACT) for existing equipment. While BACT has the potential to reduce emissions, it also adds significant costs to projects, which often times cancels implementation of the project. One change that would help these projects succeed would be to allow them to continue to use their existing control equipment as opposed to having to upgrade to the very latest technology as required by BACT. A streamlined approach could offer a solution that allows more marginal environmental benefits for these projects, while realizing the benefits that CHP can offer for better energy efficiency.

RESPONSE OF KEVIN A. KELLY TO QUESTION FROM SENATOR STABENOW

Question 1. I understand the generation of heat and power accounts for more than two-thirds of U.S. fossil CO_2 emissions. I also understand the efficiency of generating electricity has not improved from its dismal 33 percent level since the time of President Eisenhower. Can you describe some of the policy barriers to more efficient power generation, specifically distributed generation?

Answer. I agree that if policy barriers to distributed generation were removed, the increased use of distributed generation could contribute to more efficient power generation. Some studies indicate that using distributed generation to provide both electricity and heat (for space or water heating, process heating, or even cooling) can increase total system efficiency from 33-50 percent in a typical modern central station generating plant to as high as 80 percent in a distributed generation combined heat and power system.

Many policy barriers to increased use of distributed generation, however, are found at the state and local levels. For example, manufacturers and prospective users of distributed generation equipment have expressed concern about the lack of reasonable, standardized interconnection requirements. Most interconnections of distributed generators are jurisdictional to states or local retail regulators, not the Commission. Therefore, the above-noted concerns remain despite the Commission's issuance of regulations that standardize interconnection procedures for small generators whose interconnection is subject to the Commission's jurisdiction. The Commission has encouraged state and local regulators to use the Commission's regulations as a common guideline for their own regulations.

In addition, in some cases, distributed generators have been charged exit fees by utilities to protect their other customers from the costs of past utility investments intended for the customer that later develops his own generating capability. Further, local barriers to distributed generation include such policies as local siting and permitting requirements and building electric codes for onsite generation such as rooftop solar.

More broadly, prospective users of distributed generation equipment have expressed concern that policies that make it difficult for distributed generation to be compensated commensurate with its full value constitute significant barriers to its increased use. For example, many states require (to the extent of the state's authority) that when distributed generation produces more electricity than is needed by its host user, the excess output can be purchased only by the local distribution utility. In such situations, the user of distributed generation may have little ability to negotiate a sale price with the local distribution utility or to sell the output to a neighboring utility customer at the retail rate and, therefore, will usually receive compensation at or near a wholesale average rate that fails to reflect all value associated with the distributed generation (e.g., producing electricity close to load, avoiding transmission and distribution losses and investment, and providing other reliability or environmental benefits to utility systems). Thus, typical compensation from the distribution utility may make investment in distributed generation less attractive than it might be.

RESPONSES OF KEVIN A. KELLY TO QUESTIONS FROM SENATOR RISCH

Question 2. With regard to net metering, what are potential impacts on the transmission and distribution system?

Answer. Net metering can have significant positive impacts on the transmission and distribution system. For example, distributed generation dispersed within the distribution system can provide voltage support for the system and lessen the amount of additional distribution and transmission investment that will need to be made, thus reducing costs for all consumers on the system. In addition, targeted distributed generation can relieve local transmission congestion and thereby lower electric market prices to consumers.

Widespread deployment of net metering may also call for other system upgrades. For example, distribution lines may require modifications to accommodate power flowing in the opposite direction from that for which the lines were designed.

Question 3. FERC currently has limited authority with regard to net metering and distributed generation interconnection standards—it only applies to facilities that are already subject to the Commission's jurisdiction (wholesale facilities). Is FERC advocating the expansion of its current authority under the Federal Power Act with regard to these standards?

Answer. No.

RESPONSES OF CHRISTOPHER COOK TO QUESTIONS FROM SENATOR RISCH

Question 1. In your testimony, you state that meters installed in the 1950s and 1960s by utilities would net meter, simply spinning in reverse when a generator on the customer's side was producing more power than the customer was using. How can we simplify and streamline the existing framework for net metering?

Answer. Any funding for utilities to replace meters with smart meters or any meter upgrade should include a requirement that the new meters provide net metering. Some new electronic meters are designed in such a way that they do not spin in reverse while others are designed to provide for net metering and reverse spin and registration. Utilities should only install meters that will spin in reverse and provide net metering so as to avoid the added cost of replacing a meter when a customer adds a wind or solar system to power their home or business.

There should be a minimal national standard for net metering that embodies the fundamental premise that if a customer generates a kilowatt-hour of energy from their own renewable energy system, they receive a full kilowatt-hour credit for that generation to be used against future consumption. There should be no set-offs or reduction in value through fees or charges imposed on customer-generators. Federal guidelines on the allowable size of systems would help streamline and create a national seamless standard for net metering.

Question 2. You note that one of the most prominent questions about net metering is whether power producers that are benefitting from net metering are paying their fair share of costs. Why shouldn't a net metered customer be responsible for the administrative costs associated with net metering?

Answer. Net metering should be implemented in the simplest and least cost manner. If undertaken with this direction, administrative costs should be minimal to non-existent. Where utilities have in place meters that can net meter (meaning the utility has not replaced the old fashioned meters with a version that no longer net meters) the meter does all of the administrative work spinning forwards when the customer's generator is less than their load; spinning in reverse when the generator is greater than the load and at all times showing the "net" amount of consumption. When the utility meter reader reads the meter monthly (or other billing period) the meter shows the net of production against consumption and the customer is billed like any other utility customer. In this case there are no administrative costs. Where the meter shows an excess, the utility can just issue a zero bill for that month and subsequent months until excess credits are used up. There is no need to track the excess as again the meter keeps an accounting. There may be minimal administrative costs for reconciling annual excess energy under the rules where a customer is paid annually for excess at avoided cost. The simpler and less costly option is to either eliminate excess credits at the end of the year or allow for continued carry forward. In the former case there is some administrative cost but the utility is getting free kilowatt-hours that help to defray that cost. In the latter case, there should be minimal to no administrative costs as billing continues like it would for any other customer.

Where administrative costs tend to be greater than an insignificant amount are in the cases where a utility has undertaken a meter replacement and the new meters no longer provide the net metering function. In those cases the burden of meter replacement cost or using a dual meter arrangement (which requires monthly accounting) rightly falls on the utility since one may question the judgment of a meter replacement that eliminated the simple net metering function.

Question 3. You noted in your testimony that if a customer/generator could use storage, they could store peak energy for off-peak usage. What kind of storage are you referring to? What kind of storage for solar energy is commercially available today?

Answer. Batteries; compressed air and thermal storage[1] are the most common forms of storage available today. Flywheels and electrolysis hydrogen production/

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[1] electrical energy is used to make heat or ice and stored for later heating or cooling of a building.

fuel cells have future potential as storage devices. In most cases and under system operator rules for the grid, the additional cost of storage is not economical.

Moreover, using solar power that is typically produced during grid peak times and putting it into storage is not good for the electric grid, as the grid can best utilize this valuable energy. It is better to have the solar customer-generator put excess peak power into the grid (and not into storage), receive a credit for the power put into the grid and then have that customer use off peak power when the sun is no longer shining. This is more economical and better for the electric grid than taking that excess peak solar energy and putting it into batteries and then drawing from the batteries when the sun is not shining.

An example: Grid peak capacity = 1000MW. Total capacity of solar generators = 50MW.

On a peak load day during the daytime when load reaches 1000MW, the grid teeters on the brink of a blackout. If the 50MW of solar generation is put onto the grid through net metering, the total load is reduced to 950MW reducing the critical level of the peak load. Conversely, if there is no net metering and customers are putting their excess power into batteries, the 50MW is not available to the grid (that generation is all going to storage) and the grid continues to struggle with a peak load that has reached the capacity of the grid generators.

[Responses to the following questions were not received at the time the hearing went to press:]

QUESTIONS FOR DAVID WEISS FROM SENATOR STABENOW

Question 1. FERC has fairly narrow jurisdiction over the regulations that affect distributed energy. Could you talk a bit more about the federal options beyond regulation? The challenges we're hearing about today will require lots of creativity to overcome. In particular, what authorities does the Department of Energy have to encourage the deployment of distributed generation-both small-scale wind and solar as well as industrial-scale Combined Heat and Power? Can these authorities be made more effective?

QUESTIONS FOR DAVID WEISS FROM SENATOR RISCH

Question 2. In your testimony, you advocate for rate decoupling. Can you explain further how you think this would strengthen and improve the use of distributed generation?

Question 3. As you stated in your testimony, subsidiaries of Pepco serve customers in Delaware, the District of Columbia, Maryland and Jew Jersey. Please describe some of the pros and cons of different frameworks from state to state, as well as why you believe there should be a federal model, as opposed to a national standard, that allows for flexibility across state lines and also allows local stakeholders the opportunities to shape their own policies.

Question 4. Feed-in tariffs are an incentive structure whereby utilities are obligated to buy electricity (typically renewable) at above-market rates set by the government, encouraging rapid consumer growth. What is your position on feed-in tariffs?

Appendix II

Additional Material Submitted for the Record

Statement of the American Forest & Paper Association (AF&PA)

introduction

The American Forest & Paper Association (AF&PA) appreciates this opportunity to present its views for the hearing on purpose of the hearing "net metering, interconnection standards, and other policies that promote the deployment of distributed generation to improve grid reliability, increase clean energy deployment, enable consumer choice, and diversify our nation's energy supply." AF&PA is the national trade association of the forest products industry, representing pulp, paper, packaging and wood products manufacturers, and forest landowners. Our companies make products essential for everyday life from renewable and recyclable resources that sustain the environment. The forest products industry accounts for approximately 6 percent of the total U.S. manufacturing GDP, putting it on par with the automotive and plastics industries. Industry companies produce $200 billion in products annually and employ approximately 1 million people earning $54 billion in annual payroll. The industry is among the top 10 manufacturing sector employers in 48 states.

af&pa members' energy profile and greenhouse gas reductions[1]

Overall Efficiency

AF&PA members have steadily increased their energy efficiency, while also increasing reliance on carbon-neutral renewable biomass power, and reducing fossil fuel use. Overall, total energy use per ton of production at member pulp and paper mills has decreased by 26.6 percent since 1972, and by 11 percent between 1990 and 2006.

Combined Heat and Power

One of the ways in which members have increased their efficiency is through the use of combined heat and power (CHP), which is the practice of using exhaust steam from electrical generators for heat in manufacturing processes or for space heating. Based on U.S. Department of Energy (DOE) data from 2007, the forest products industry is a leader in the use of CHP-generated energy—99 percent of the pulp and paper mills that generate electricity employ cogeneration technology. The forest products industry represents one third of the industrial CHP-generated energy in the U.S.

Renewable Biomass Energy

The forest products industry also is the leading producer and user of renewable biomass energy in the U.S. In fact, the energy we produce from biomass exceeds the total energy produced from solar, wind, and geothermal sources combined. Sixty-five percent of the energy used at AF&PA member paper and wood products facilities is generated from carbon-neutral renewable biomass.

Fossil Fuel and Purchased Energy

Our increasing efficiency and greater reliance on biomass energy has enabled AF&PA members to significantly reduce the use of fossil fuel and purchased energy,

[1] AF&PA member performance metrics are from 2008 AF&PA Environmental, Health & Safety (EHS) Verification Program Biennial Report, 2008 (http://www.afandpa.org/Content/NavigationMenu/Environment__and__Recycling/Environment,__Health__and__Safety/AF&PA__EHSReport08__final5web.pdf. Industry statistics on cogeneration are from: 2007 energy cogeneration data from the Energy Information Agency (http://www.eia.doe.gov/cneaf/electricity/page/eia906__920.html.)

much of which also is generated from fossil fuel. From 1972 to 2006, the fossil fuel component of the AF&PA member mill energy mix decreased by over 55 percent, and the use of both fossil fuel and purchased energy has decreased by 56 percent.

Greenhouse Gas (GHG) Reductions

Our commitments to energy efficiency, CHP, renewable biomass energy, and other actions have enabled AF&PA members to achieve significant reductions in GHG emissions. Since 2001, working together AF&PA members voluntarily reduced their carbon dioxide (CO_2) emissions intensity by 13 percent. From 2000 to 2006, our members collectively reduced their direct greenhouse gas emissions 34 percent. Approximately half of this reduction can be attributed to improvements in greenhouse gas emissions, such as efficiency improvements or reduced fossil fuel use, and half can be attributed to decreases in production and changes in the baseline from the year 2000.

The Benefits of CHP

CHP is the sequential or simultaneous generation of electricity and thermal energy (in the form of steam) from the same fuel for use at a host facility that makes both electricity and another useful product or service requiring heat. CHP is more efficient because it generates both thermal energy and electricity concurrently rather than generating thermal energy onsite and electricity at utility generators remotely. By producing electricity and process heat, relatively little heat value of fuel is wasted to the environment compared to conventional utility generating processes; this is the basis for the savings. In general, CHP is about twice as efficient at using fuel as is utility technology. This relative energy efficiency of CHP results in decreased emissions of carbon dioxide to the atmosphere. CHP generation of electricity emits only half as much GHG as non-CHP electricity. Furthermore, by reducing electricity demand from the grid, CHP reduces the corresponding transmission and distribution inefficiencies which are typically 7 percent. Numerous studies have documented these benefits of CHP and the role that increased CHP can play in helping the nation reduce greenhouse gas emissions, thereby also helping the nation meet its renewable energy, and energy security goals.

Barriers to Increased Use of CHP

While the industry is a leader in the use of industrial cogeneration technology, there are numerous policy barriers to increasing the use of that technology in our industry, in other industries, and in other settings, as is evident from the testimony provided for the hearing. In particular, we would like to highlight the testimony of Irene Kowalczyk, MeadWestvaco Corporation (MWV). MWV is a member of AF&PA and Ms. Kowalczyk's testimony presents a comprehensive compilation of existing and potential future barriers to increased use of CHP in the forest products industry. We would like to highlight a few energy policy issues from her testimony that have negatively affected numerous AF&PA members:

- Interconnection Standards: Unlike merchant generators, whose purpose is to generate and sell electricity, forest products industry CHP facilities' primary purpose is to provide thermal energy for its host manufacturing facility. Policies such as interconnection standards for facilities larger than 20 MW require CHP units to go through the same costly, lengthy and complicated process that merchant generators do if they seek full compensation for the power they sell to the grid. In addition, under the rule's "deliverability standard" a new CHP unit is not allowed to compete on price with the incumbent for the use of the grid, even though the incumbent may be a less energy efficient generator. Finally, a CHP unit at a manufacturing site which is in a transmission constrained area would be required to finance transmission upgrades as part of the interconnection process before being permitted to interconnect.
- Discriminatory Treatment of Behind the Meter Generation: "Behind the Meter" generation refers to electricity generated and used on site by the manufacturing facility and not sold to a utility or an Regional Transmission Organization (RTO) or Independent System Operator (ISO). Nonetheless, RTOs and ISOs have repeatedly attempted to interfere with CHP in the area of "Behind the Meter" pricing, for example, by attempting to charge customers who supply their own needs with "Behind the Meter" generation various fees and prices for services as if they had taken their entire power supply from the RTO/ISO—controlled grid, rather than only the "net" amount actually taken from the grid. This cost allocation scheme is known as "Gross Load" pricing and is a barrier to increased CHP use.
- PURPA Rules: The Energy Policy Act (EPAct) of 2005, substantially revised the Public Utility Regulatory Policy Act (PURPA) of 1978 to allow utilities to be re-

lieved of their mandatory obligations to purchase electricity from Qualifying Facilities if the utility could demonstrate that it was operating in a competitive market. Under the Federal Energy Regulation Commission's (FERC) final order implementing the law, however, utilities are not required to demonstrate that their markets were functionally competitive before being relieved of those obligations. In effect, the utility simply has to be a member of an established RTO or ISO to be exempt. This rule will make it much more difficult for CHP units to negotiate fair power purchase contracts in the future. AF&PA challenged the final order, but in a mid-December 2008 ruling, the D.C. Circuit Court affirmed the FERC's decision.

These are just a few of the policy barriers to increased CHP use that forest products and other industry facilities have faced. As Congress develops energy (including renewable energy) and climate change legislation, it should seek opportunities to provide incentives and promote the use of CHP. Thank you for your consideration of this Statement.

STATEMENT OF SUZANNE WATSON, J.D., LL.M., POLICY DIRECTOR, AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE)

INTRODUCTION

ACEEE is pleased that the subcommittee is exploring interconnection and other policies that promote clean distributed generation. One form of distributed generation, called combined heat and power (CHP), offers the promise of significant increases in energy efficiency and reductions in harmful emissions in a number of applications and sectors. Waste heat recovery, which can take the form of CHP, offers similar benefits and is affected by many of the same policies and regulations as CHP. A variety of policy and regulatory issues affect the deployment of CHP and waste heat recovery systems (hereafter referred to simply as "CHP"), including interconnection standards, output-based emissions standards, standby electric rates, natural gas rates and financial incentives.

ACEEE regularly assesses a number of these policies for each U.S. state, and ranks states according to their CHP policies in the annual ACEEE State Energy Efficiency Scorecard. Below is a brief discussion of the policy and technical issues associated with CHP, what constitutes "good" policies in some of these categories, and a ranking of states based upon their CHP policies. What is important to note is that these policies vary dramatically among states, leaving CHP project developers with a heterogeneous policy and regulatory landscape in which to work. Each state has different rules, processes, forms, timelines and fees associated with a number of these policies, which serve to add to the overall administrative cost of a project being done in an unfamiliar area. Some states have very user-friendly policies, while others have policies actively hostile toward significant CHP deployment. Streamlining some of these policies to provide a more homogeneous policy and regulatory landscape for projects would serve to reduce administrative cost, provide greater degrees of certainty to project developers, and encourage CHP in areas that have policies and regulations that discourage CHP.

WHAT IS COMBINED HEAT AND POWER?

CHP systems generate electricity and useful thermal energy concurrently in a single, integrated system. CHP is not a single technology, but an approach to applying new and existing technologies. It is a form of distributed generation, generally located at or close to the point of consumption, unlike traditional centralized generation. So rather than purchase electricity from the grid and then burn fuel onsite in a boiler, the owner of a CHP system can get both electricity and thermal energy from one energy-efficient system.

The average centralized electric power generation plant is 35% fuel efficient, losing most of its useful energy as waste heat at the point of generation. A CHP system captures this heat and repurposes it to meet onsite thermal requirements for heating (or cooling, using additional cooling technologies). And while an additional 3-10% of typical centrally generated electricity is lost in the course of being transmitted and distributed to end-users, CHP boasts very few transmission and distribution losses, as the energy is generated very close to the point of consumption—often in the same building. All together, CHP systems are typically about 60-80% fuel efficient.

CHP systems can be powered by a variety of fossil and renewable-based fuels, and are found in a variety of places, including industrial facilities, large institutional campuses, hospitals, multi-family housing complexes and commercial buildings.

CHP currently represents about 8.6% of all U.S. electricity generation capacity. DOE estimates that figure could rise to 20% by 2030 if a suite of "pro-CHP" policies was implemented.[1]

BENEFITS OF COMBINED HEAT AND POWER

Since less fuel is required to produce the same amount of useful energy, and little energy is lost as it moves to its point of consumption, CHP systems provide environmental and economic benefits. They also provide benefits to the electricity grid at large. In general, CHP produces electricity at about $0.06-$0.08/kWh, while the current retails cost of electricity from centralized generation is nearly $0.10/kWh.[2]

Today's existing fleet of CHP systems provides the country with 85 GW of electricity capacity—replacing the need for about 2 Quads of centrally-generated energy on an annual basis. This current CHP fleet yields:

- An annual reduction of 248 MMT of CO_2 (about 45 million cars off the road)
- Reductions of over 50% in energy costs at facilities that use CHP
- Significant reductions in costly congestion on transmission and distribution lines

If CHP were aggressively supported by national policies, growing its role to 20% of all U.S. generating capacity by 2030, the benefits would be pronounced. At 20% of all electricity generation, CHP would replace the need for about 5.3 Quads of centrally-generated energy annually. This amount is equivalent to about half of the amount consumed the by U.S. residential sector each year. A 20% scenario would:

- Provide an annual reduction of 848 MMT of CO_2 (154 million cars off the road annually)
- Create 936,000 net jobs
- Stimulate the economy with an influx of CHP-related investments of $234 billion
- Avoid 60% of the expected increase in total U.S. CO_2 emissions between now and 2030[3]

EXISTING BARRIERS TO GREATER ADOPTION OF CHP

Despite its cost-effectiveness and potential for significant environmental benefits, significant hurdles remain that limit widespread use of CHP. As a result, less-efficient separate heat and power systems still predominate. Three areas that pose significant challenges to the increased deployment of CHP are:

Interconnection standards

A major barrier to CHP is the lack of national business practice standards for the interconnection of CHP to the local electric utility grid. Interconnection is the process of connecting a CHP system to the transmission and distribution grid, and is necessary if the facility wishes to purchase backup power from the grid or sell electricity back to the grid if desired. The lack of national uniform interconnection standards results in a patchwork of regulatory models that vary from state to state. About half of the U.S. states have no interconnection standards for CHP at all. CHP system manufacturers cannot view the U.S. as a uniform market, and CHP users cannot be assured that what works in one facility will work in another one across state lines. A lack of uniform standards causes uncertainty, too, since some standards have set timeframes during which a CHP system will be allowed or denied interconnection, while other standards do not. The local interconnection regulations can also impact the size and design of a CHP system. Further, some utilities require costly studies or the installation of unnecessary (and expensive) equipment prior to interconnection, discouraging CHP.

Standby and backup tariffs

Many utilities also currently charge discriminatory rates for standby and backup power services that don't reflect the true costs and benefits to utilities of having CHP systems in their service areas. Standby service rates are charges that are incurred by a CHP user when their CHP system goes down due to an emergency or scheduled maintenance outage. Standby charges are generally composed of two elements: a charge for the actual en-

[1] http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp__report__12-08.pdf
[2] http://www.eia.doe.gov/cneaf/electricity/epm/table5__6__b.html
[3] http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp__report__12-08.pdf

ergy used (energy charges) and a charge reflective of the peak one-time demand of the standby power (demand charges). Energy charges better reflect the true economics of CHP than do demand charges, but the majority of standby rates are weighted heavily toward demand charges. Backup power is the additional electricity a CHP-using facility purchases to supplement its CHP power output to meet the entire onsite load requirement. Though backup power usage characteristics are similar to those of a facility not using CHP, some utilities discriminate against facilities that have CHP and use different rates to charge for backup power than a non-CHP facility.

Private wires regulations

Many states and cities restrict the use of public right-of-ways to utilities for the construction and operation of energy distribution systems. This restriction has posed a barrier to many CHP systems since a CHP-using facility is prohibited from selling excess thermal or electric power to a neighboring facility if that energy would need to use private wires to cross a public right-of-way. If facilities could connect with nearby facilities via access to these private wires, the viability of CHP systems could be increased. Facilities with complementary energy use patterns could share access to a single CHP system. The economies of scale found in aggregating the energy demand of multiple facilities would make CHP even more economically attractive.

2008 ACEEE CHP SCORECARD

In 2008 ACEEE assessed how each U.S. state was doing relative to five CHP policy categories, including the first two listed above: interconnection standards and standby/backup tariffs. An excerpt of that research is presented below to give an overview of the varied landscape CHP systems face. The overall score for each state as determined in the 2008 scorecard is given as well. For context, that overall score incorporates the two noted categories as well as three others: the presence of CHP financial incentives, the ability of CHP to qualify for a state's energy efficiency or renewable energy portfolio standard if present, and the use of output-based air emissions regulations.

States are rated on interconnection and standby rates according to this scheme:

Interconnection:

●● = Very good, "pro-CHP" interconnection standard in place
● = Interconnection standard in place does explicitly allow CHP
●^ = Proposed interconnection standard will allow CHP
(blank) = No interconnection standard at all; or existing one explicitly does not allow CHP

Standby Rates:

Standby rates are rated on a scale of 0-3, with 3 being the best, and actively promoting CHP; 2 being neutral toward CHP; 1 being slightly negative toward CHP; and 0 actively discouraging of CHP.

Table 1: 2008 ACEEE CHP Scorecard Results

Rank	State	Interconnection	Standby Rates	Overall Score
1	California	●●	2	8
1	Connecticut	●●	1	8
1	New York	●●	1	8
1	Wisconsin	●●	2	8
5	Illinois	●	2	7
5	Ohio	●	1	7
5	Oregon	●	2	7
5	Texas	●●	2	7
5	New Jersey	●●	2	7
10	Pennsylvania	●	2	6
10	Washington	●	1	6
12	Colorado	●	2	5
12	Delaware	●	2	5
12	District of Columbia	●^	3	5
12	Hawaii	●	2	5
12	Indiana	●	2	5
12	Maine		3	5
12	Maryland	●	2	5
12	Massachusetts	●●	1	5
12	Minnesota	●●	2	5
12	Vermont	●	1	5
22	Florida	●	1	4
22	Idaho		2	4
22	Michigan	●	0	4
22	North Carolina	●	1	4
26	Alaska		2	3
26	Arizona	●^	2	3
26	Missouri		2	3
26	New Hampshire		2	3
26	New Mexico	●	0	3
26	South Dakota	●^	1	3
32	Arkansas		1	2
32	Kansas	●	0	2
32	Mississippi		1	2
32	Montana		2	2
32	North Dakota		1	2
32	Rhode Island		2	2
32	South Carolina	●^	0	2
32	West Virginia		2	2
40	Alabama		0	1
40	Iowa	●^	0	1
40	Kentucky		1	1
40	Nebraska		1	1
40	Nevada		1	1
40	Oklahoma		0	1
40	Tennessee		1	1
40	Utah		0	1
40	Virginia	●^	0	1
49	Georgia		0	0
49	Louisiana		0	0
49	Wyoming		0	0

CONCLUSION

Given the clear benefits that CHP delivers to the nation and recognizing that the removal of certain long recognized barriers as indicated above would facilitate an increased amount of it, the following recommendations are suggested:

1. For systems 2 megawatts and under, allow a more streamlined, expedited process be utilized in terms of safety studies, application process, fees, and any other burdensome and unnecessary business practice imposed for interconnecting;
2. Scale stand-by tariffs and back-up fees to a level that is affordable to these smaller sized systems;
3. Set up an annual review process during which all aspects of the interconnection process is reviewed and evaluated based on how much additional CHP occurs. This review process should look to make needed changes to the utility business practices if determined still unduly burdensome; and
4. Create a net metering system for systems 2 megawatts and under that rewards and encourages their installation.

STATEMENT OF KENT JEFFREYS, STAFF VICE PRESIDENT, INTERNATIONAL COUNCIL OF SHOPPING CENTERS

Thank you for this opportunity to add to the record of your May 7, 2009 Subcommittee on Energy hearing to investigate net metering and other policies that promote the deployment of distributed generation and improve grid reliability, increase clean energy production, expand consumer choice and diversify our nation's energy supply.

The International Council of Shopping Centers (ICSC) is the premier global trade association of the retail real estate industry. Founded in 1957, ICSC has more than 70,000 members in the U.S., Canada, and over 90 other countries. ICSC represents owners, developers, retailers, lenders, and other professionals as well as academics and public officials. ICSC has over 5,000 public sector members including mayors, city managers, and economic development and planning professionals. Among its many initiatives, ICSC promotes retail development in underserved urban and rural markets. ICSC's award winning Alliance Program encourages public-private partnerships and open dialogue on emerging issues impacting the retail real estate industry and the quality of life in local communities, including sustainability and energy efficiency.

For many years, some states have required that electric utilities offer customers the option of "running the meter backwards" if the customer generates her own power. Unfortunately, in most parts of the country, this option only has been available to residential or small commercial customers. In most jurisdictions "net metering" has significant limitations including extremely low compensation for any excess electricity generated and strict limits on how much power, in total, may be generated annually. Obviously, these facts stand in the way of fully utilizing the vast roof space available for solar panel installation at commercial property sites across America.

In response to this situation, Congress passed the Energy Policy Act of 2005 and amended Section 111(d) of the Public Utility Regulatory Policies Act (PURPA) to require that utilities with greater than 500,000 MWh of annual retail sales consider setting standards for interconnection and net metering by August 8, 2008. There was no requirement that these entities actually adopt more robust net metering standards or alter pre-existing approaches to net metering. As a result, only a few states have improved their net metering rules in the intervening years—often as the result of popular demand from local citizens. Yet in the absence of a minimum national net metering standard, America is not producing nearly as much renewably generated electricity as it could. And the patchwork quilt of state regulations further hinders national real estate firms from aggressively responding to the nation's need for distributed generation and renewable power.

Opposing arguments have included a concern over potential safety issues such as the worry that allowing thousands of small power generators to hook into transmission lines could run the risk of electrocuting workmen who fail to properly disconnect the private systems during repair or maintenance. The truth is that proper interconnection standards easily deal with safety concerns and, where they have been instituted, have allowed net metering to continue without mishap. The safety issue is largely a red herring.

In addition, some utilities have argued that allowing even a relatively small percentage of private power onto the grid could destabilize the whole system. Yet experts assure us that even if 15 or 20 percent of baseload electric demand were supplied by wind, solar and other renewable power from private sources it would not destabilize the ability of the grid to respond to changing levels of demand. For example, Germany has successfully integrated a far larger percentage of renewable power into its national grid than the United States and continues to expand its capacity. In addition, Congress has already approved funding to accelerate the conversion of America's existing transmission capacity into the "smart grid" of tomorrow—further reducing the concerns of a destabilized transmission network.

A final argument against national net metering has been that local ratepayers have funded the existing transmission grid. Therefore, it has been argued, allowing customer-generated power onto the grid would amount to a huge subsidy. In addition to being trumped by high-priority national concerns (potential climate change and oil imports from unstable regions, for example), and the fact that customer-generators are also ratepayers, the "subsidy" argument can be addressed by establishing modest and fair access rates to transmission lines. However, these charges should be allowed only when the customer-generated renewable power is, in fact, distributed beyond the local area and relies upon the regional transmission system.

A strong case can be made that national energy policy should allow—even encourage—customers to generate more "green power" than they consume each month.

The excess electricity should be delivered (via the local transmission lines) to other local customers without arbitrary and excessive fees or unnecessary technical obstacles such as redundant or needlessly expensive interconnection standards.

When solar photovoltaic is generating the renewable power, the electricity is usually generated during the "peak demand" periods of the day. Peak demand places a strain on existing baseload capacity—both generation and transmission. Electric utilities reflect this higher demand (and related strain on the system) by charging more per kilowatt for the electricity during peak periods. Therefore, rather than creating a new problem for the electric grid, on-site solar is providing a solution to an existing problem.

Any national net metering standard will need to address the question of pricing levels. Currently, in most circumstances customer-generators are able to offset kilowatts purchased from the grid on a penny-for-penny basis—but only up to the point where they completely "net out" against their monthly charges. At that point, various rules may apply in various jurisdictions. Most often, excess electricity from the customer-generator only receives the so-called "avoided cost" or "incremental cost" for the utility company. Avoided costs are generally around one or two cents per kilowatt-hour while normal retail prices across the country are far higher. In other words, where avoided costs apply the customer-generator is effectively subsidizing the utility company whenever she produces excess electricity.

Such low levels of compensation for excess capacity act as a disincentive for customer-generators to contribute as much renewable power as their site can produce. Establishing a national net metering price "floor" tied to local retail prices (which vary around the country) could unleash the market for renewable power across the country. Arguments to the contrary are similar to arguments against universal service charges and can be dealt with through regulatory hearings conducted by the Federal Energy Regulatory Commission. Yet without specific guidance from Congress, net metering will only expand slowly in the handful of states that have robust net metering laws already on the books.

ICSC believes that stronger incentives for consumer-generated "green" power would enhance national security, reduce imports of foreign oil, create local jobs, reduce the need for new long-distance transmission lines, create more power during peak demand periods, reduce the risk of blackouts and brownouts and cut by approximately 90 percent the amount of pollution (including greenhouse gases) for each kilowatt of solar that replaces coal-fired power.

The time has come for a minimum national standard for net metering sufficient to stimulate a greatly expanded capacity for on-site renewable power generation. This committee is to be commended for reviewing the recent progress—or lack thereof—on net metering and associated interconnection standards.

Again, thank you for this opportunity to provide input during this important national debate.

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