Federal Energy Regulatory Commission

Technical Conference on Implementation Issues Under
The Public Utility Regulatory Policies Act of 1978

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P R O C E E D I N G S

(9:05 a.m.)

MR. GREENFIELD: Good morning. And welcome to today's conference on the Public Utility Regulatory Policies Act of 1978, or PURPA, as it is affectionately known. I'm Larry Greenfield and I am the Associate General Counsel in the Office of General Counsel here at the Commission. And to my left is Julie Simon, Senior Policy Advisor with the Office of Energy Market Regulation.

We will be leading the Technical Conference today. I do want to thank all of the participants, both in this panel and this afternoon, for being here and for what I'm sure will be an informative day of discussion on this topic.

I also want to thank the Commissioners, Commissioner LaFleur and Commissioner Clark, who are seated to my left. The purpose of this conference, of course, is to obtain information and examine the Commission's implementation of PURPA in light of recent developments in electricity markets.

In the morning, we will focus on issues related to the mandatory purchase obligation. After lunch, we will focus on various methods for calculating avoided costs. This Technical Conference will not, however, address any statutory changes to the law.

While we have included a number of pending matters in the notice of this Technical Conference, which we issued a supplemental notice on the other day, the Conference is not for the purpose of discussing specific cases. Thus, panelists should refrain from discussing the specifics of any cases pending before the Commission to avoid any ex parte concerns.

We will begin each panel with brief statements from each of the panelists. We ask that you limit your opening remarks to three to five minutes, so that we have adequate time for discussion. We will then move to a question and answer format. We will not necessarily be addressing all questions to all of the panelists in a given session, but rather we may direct questions to particular panelists in order to discover specific information that will help the Commission staff, and ultimately the Commission better understand the issues presented to us.

This is an on-the-record conference and it will be transcribed. Any materials received from speakers will be included in the record. As noted, we will have two sessions today. The first session on issues related to the mandatory purchase obligation is scheduled to run until approximately noon.

This session addresses when a QF can be curtailed, the impact on interconnection of QF transactions, the obligation to purchase pursuant to legally enforceable obligations, or LEOs, and the effect the emergent energy imbalance market in the West may have on the mandatory purchase obligation.

The second session is scheduled for roughly 1:00 to 3:30, and we'll discuss various methods for calculating avoided cost, including the system average method, the use of natural gas prices and other fuel indices and setting avoided costs, and setting avoided costs through auctions and/or requests for proposals.

We do have a lot of ground to cover in a relatively short amount of time today. With that in mind, if the discussion begins to stray outside the scope of the panel or outside the scope of the question, we may interject to bring the discussion back to the topic.

And let me close with a few housekeeping matters. Please, per Commission policy, do not bring food or drinks, other than bottled water, into the Commission meeting room. Please turn off your cell phones, if you have not already done so. And there are bathrooms and water fountains located behind the elevator banks on each side of the building for those of you who have not been here before.

For panelists, if you would like to be recognized to speak in response to a question or a comment said by another speaker, please do place your tent up. Also when you are speaking, be sure to turn on your microphone and speak directly into it. When you're not speaking, do please turn off your microphone to minimize background noise. I realize that can be difficult to remember, but do your best to avoid forgetting what to do with the microphone.

Also, while it can be difficult to do this particularly, myself and others, do your best to avoid using acronyms or abbreviations. With that, I would like to turn it over to the Commissioners, Commissioner LaFleur and Commissioner Clark, for their introductory remarks.

COMMISSIONER LAFLEUR: Well, thank you very much, Larry. And thank you to everyone on staff for pulling together such a quality conference. I am really happy to be here. This is a topic, very timely, that I'm very interested in. I'll try to be here for as much of the day as I can, bearing in mind that we haven't left this room since Monday morning.

It's somewhat sobering to think that I've been involved in PURPA in some way, shape or form since the mid-80s. I was actually closely involved in writing one of the very first PURPA contracts up in the New England area, the interconnection group worked for me, the new interconnection group. Because that was such a scary thought, whatever an interconnection was.

And I think it's worth reflecting that, in many ways the law we're talking about today gave rise to so many of the changes that have shaped and royaled this industry over the last decades, the growth of the independent power industry, the birth of so many renewables and so forth. Those same changes that PURPA helped spawn have made PURPA administration a lot more challenging and I'm sure that's a lot of what we're going to talk about today.

Since being at FERC, I've tried to faithfully execute the law, being mindful that it was reaffirmed by Congress as recently as 2005. I just want to underscore something Larry said. What would be most helpful, at least to me and building the record would be suggestions for any action that you want FERC to take to change our work on this or strengthen or anything else, not calls for statutory change, much as we're interested in your thoughts, you have to go up the Hill for those, because we don't have that kind of power. Thank you very much.

COMMISSIONER CLARK: I do wish to thank everyone for being here today, and thanks to Chairman Bay for scheduling this conference, and to staff for all of your work pulling it together. I'm wearing my purple tie in honor of PURPA today. I'm looking out there. Mr. Hughes, you get a gold star. I don't know if I see a lot of other purple ties or clothes, but if you do, congratulations.

PURPA, much like myself, was born in the 1970s, and things do change over time. When it was first introduced, a lot of the technologies that we're probably going to be talking about today were very boutique-y in nature and PURPA was, in essence, a foot in the door for some of these technologies.

But things evolve over time. Technologies changed. Markets change. The nature of the size of things like wind farms that get sited, change. And so as all of that happens, it always makes sense for us as regulators for those things that are within our power to make sure that at least those aspects of the regulation that we have control over. And there are lots of things that are in the statute that we don't.

But at least those things that we do have control over make sense in the context of the way things are working today and making sure that they're working for the benefit of consumers, which is really what, at the end of the day, we're concerned about.

So I think that the record that we're going to help develop will be very useful in that regard. We're hearing anecdotally concerns from various parts of the country, especially, I think, in the West, probably is where we've heard a lot of the concerns with regard to PURPA and certainly the number of cases that we've seen have tended to be, in large part, from that region of the country.

So I think it'll be especially helpful to put a little meat on the bones, to understand a little bit better exactly what the concerns are -- what's working with it, but also what may need to be tweaked. So I also would share Cheryl's admonition -- to the degree you can, be as specific as you can about what you would like the Commission specifically to do, if anything, to either strengthen it and make it work better or to tweak it so that it acknowledges the changes that have taken place over the decade since PURPA has been in effect. Thank you.

MR. GREENFIELD: And with that, I will turn it over to Julie Simon, who will be leading the morning panel.

MS. SIMON: So thank you all for being here today. If it's Wednesday, it must be PURPA and FERC's Tech Conference Week, so with that, I'm going to ask each of the speakers to give a brief opening remark. After about five minutes, Adam Alvarez will let you know that you should be wrapping up. And then we will turn to questions. So with that, Mr. Bayless?

MR. BAYLESS: Thank you very much. My name is Charlie Bayless and I'm here on behalf of the North Carolina Electric Membership Corporation. North Carolina is currently one of the fastest growing renewable states in the U.S. There's thousands of megawatts of solar and wind planned for the state in the future. There's hundreds of projects in the interconnection queue right now.

Many of NCMC's members -- we have twenty-six distribution co-ops -- participate in the development of renewables, either through community solar partnering with QFs to promote economic development in the world communities that they operate in.

However, as one of the fastest growing renewable states, we also have concern about the effects of the mandatory purchase obligation and the impact of infusing large amounts of variable generation into the operation of the grid.

When PURPA was first enacted, QFs were trying to get a foot -- or renewables in general, were trying to get a foothold into the market. A lot's changed since then. In 2015, wind and solar accounted for 61% of new generation built. In 2016, the EIA expects sixteen of the twenty-six gigawatts of generation to be built, will come from renewables. And finally, the EIA expects this year that about 14% of the total megawatt hours generated would come from renewables.

Because of the prevalence of renewables, the mandatory purchase obligation, I think, needs to be revisited. It's time to go past the simple requirement to purchase renewables and consider the need for the renewables and the costs associated with the renewables.

I think this is especially true in states that have RPS requirements. Requiring utilities to purchase from QFs in these states, in addition to their RPS goals -- sometimes they align, sometimes they're in addition to -- could have unintended consequences and impose additional costs. First, the reliability may be affected.

The grid has the ability to absorb a certain amount of generation, but after you reach a tipping point, it may affect the reliability of the grid. At this point, once you reach a certain saturation, you have to plan this generation into the system better. You have to look at things such as reserves, generator inertia, VARs, things like that, then make sure the system remains reliable.

These problems are exacerbated by the mandatory purchase obligation because under that, renewables are usually sited where it's most economical for the QF, not in places where it's best for the system overall. So in the end, I think the mandatory purchase obligation needs to be reconsidered, and look at the best operations for the grid as a whole, instead of just forcing utilities to purchase from QFs. And that will ensure that renewables are planned for, all costs are considered, and the cost to consumers remain equitable. Thank you very much.

MS. SIMON: Thank you. Mr. Bloom?

MR. BLOOM: Good morning. My name is Jerry Bloom and I'm here this morning on behalf of the California Cogeneration Council. We represent gas-fired facilities operating throughout California and these facilities operated are located with industrials, manufacturers and institutions such as schools, hospitals, prisons.

I'm feeling a little old today, because my experience with PURPA started in 1970s when I was in law school, when I worked as a legislative assistant, and then worked on the FERC implementation regulations and then throughout the country before Public Service Commissions who were implementing PURPA. Needless to say, I have a long history with these issues.

From my experience, I can say unequivocally, without PURPA the mandatory purchase obligation, avoided cost pricing and nondiscriminatory backups, standby and maintenance service, we would not have an independent power industry, and as the Commissioner just said, we wouldn't have had led to the deregulation and the competitive markets that exist in many parts of the country.

As I reviewed the opening statements filed by participants and Mr. Bayless' last comments, I want to make one thing perfectly clear up front. What we're hearing about over and over again, and all the comments that were filed, in terms of mandatory purchase obligation, no one has identified CHP, combined heat and power cogen as the problem.

If we have issues that have developed as we go through the references, no one can be taking a position, they should be taking a position that all of the QFs are assembly situated. In fact, CHP is a very different set of issues before it today. The legal and the regulatory environment is unique and vastly different -- there are no renewable portfolio standards. There are no -- similar to what exists for renewables in many of the states.

And as we go forth and as FERC goes forth this morning, it's really important, and after this morning, for them to look at the differences between CHP QFs and renewable QFs and looking at what we need to do.

Having listened to the recent presentations before this Commission at a meeting from the National Labs across the country regarding grid modernization, the Commission is already aware that CHP, as a distributed generation resource, makes significant contributions to grid stability, reliability and emissions reduction. It is also a key and valuable tool in mitigating the intermittency of renewables.

In short, CHP is universally seen as a key component of our nation's energy future. Despite this universal acceptance, without PURPA and particularly the mandatory purchase obligation, it is likely that we will see no contribution from new or additional CHP as envisioned by the National Labs that testified or presented to the Commission recently.

However, as we look today at the obstacles, and what's striking to me, having fought these battles in terms of CHP and QFs for so long, that today PURPA is no less relevant than it was in 1978. Whether the markets have been deregulated or not, PURPA continues to be the cornerstone for alternative energy development.

Yes, markets have evolved and are considerably more complex. Yes, independent power industry is no longer nascent. Yes, there are RPS renewable programs in many states across the nation. However, the obstacles today are no less daunting than they were in 1978. In fact, particularly for CHP QFs, they may be more daunting.

Utilities continue to resist entering into contracts with CHP QFs and avoided cost pricing is more complex, not less complex. Where markets exist, and this is a key and important point, where markets exist, they are not for the long-term purchase of capacity and energy and particularly, there are no markets for the base-load products associated with CHP operations.

In my opening statement, I provided specifics regarding our experience in California. We eliminated the mandatory purchase obligation as part of a CHP settlement reached in 2010 between the utilities, the consumer groups and the CHP advocates.

I can tell you, based upon our experience there, that there is virtually no, or there has been no, to our knowledge, development of CHP, once we eliminated the mandatory purchase obligation. What we have remaining is the mandatory purchase obligation for under-20 megawatts.

If, in fact, we eliminate that, we will not see CHP beyond in-the-fence operations which serve just the thermal host and the load. For industrials and manufacturers that have large thermal loads that create excess energy, there simply isn't any place -- there are no viable options as to where you place that electricity, except for the sales under the PURPA.

PURPA, thus, is absolutely key to the continuation of CHP to the operations of CHP, and if we're going to meet the goals and use CHP, in terms of grid stability reliability mitigation, all the reasons that I mentioned earlier and it's key that we maintain PURPA and the mandatory purchase obligation.

And the key which I started with, which I just want to close on, is CHP is very different in terms of the way it's situated, as compared to renewables. There's a whole different set of compelling issues and we need to segregate that out.

We are not advocating here that we get rid of the mandatory purchase obligation for renewables and keep it for CHP, but we are saying, when we look at the issues, you've got to distinguish between the two groups and what's happening in the markets and the comments filed by all those who are in opposition, are taking positions in terms of the problems with too much renewable energy and how that's handled in the system, need to be accounted for when we do that. Thank you.

MS. SIMON: Thank you. Before we go to our next speaker, I noticed the chairman has joined us. Mr. Chairman, do you want to make any opening comments? Okay. Then we'll go with Ms. Bowman.

MS. BOWMAN: Good morning, Commissioners and staff. My name's Kendal Bowman. I'm Vice-President, Regulatory Affairs Policy. I'm here speaking on behalf of Duke Energy Corporation. I thank you for the opportunity to be a part of this panel.

Duke Energy's regulated utilities serve over 7.4 million retail customers across our service territories and several million more via our wholesale power cells. The cost and reliability impacts of PURPA purchases impacts all of these customers. That's why today's Technical Conference is so important. I respectfully ask you to keep these millions of customers in mind as you consider the implications that an unconditional mandatory purchase obligation has on customer rates and reliability.

We show in our file of comments that even four decades later, the foundational principles of PURPA hold the key to an implementation that best serves customers. Congress intended PURPA to be implemented based on an actual need for energy and new capacity.

Furthermore, in Order 69, the Commission said that determining avoided cost rates required taking into account the relationship of energy or capacity from a qualifying facility to the purchasing electric utilities need for such energy or capacity. Unfortunately, these principles and the needs-based application of PURPA, have been lost or forgotten by many in the industry.

With the passage of time, the implementation of PURPA seems to have morphed into a developmental tool for QFs with an unconditional mandatory purchase obligation on utilities without regard to actual needs. The implementation of PURPA should return to its founding principles of energy conservation, resource efficiency, just rates for customers and improving, not impairing, system reliability.

Specifically, QFs should be incorporated into utility generation portfolios based on actual needs, not unconditional purchases. The obligation to incorporate QFs into the system should arise after the utility has identified and committed itself to a need for energy or capacity. Like all other generators, QFs should contribute to system reliability and parallel operations with utilities.

And finally, rates should be established through bona fide offers in a non-discriminatory process. Also, some of the Duke Energy utilities operate in the PJM and MISO organized markets. For those markets, the Commission should remove the 20-megawatt purchase obligation threshold. Generators in those markets have access to the organized market and direct access to sales into those markets.

Selling into the organized markets based on signals to the market, that the markets provide, promotes rational decision-making and beneficial siting of generating capacity. By removing this 20-megawatt threshold, the Commission can ensure that no generator receives preferential treatment. Just as other generators must offer their output into the market, QFs should be required to do so by directly selling into those organized markets.

The Commissions' orders and regulations guide and provide strong signals to State Regulatory Commissions who implement PURPA in each of their states and jurisdictions. It also provides signals to the organized markets. We at Duke Energy respectfully ask this Commission to propose an issue regulations and orders that re-assert the founding principles of PURPA and the application of a needs-based approach. Thank you for the opportunity to be on the panel and I look forward to questions and answers.

MS. SIMON: Thank you. Ms. Chappelle?

MS. CHAPPELLE: Thank you. Thank you, Julie. And thank you for the opportunity to be here today, Chairman Bay and Commissioners LaFleur and Clark. My name is Laura Chappelle and I want to make sure that I get a couple of my written comments in as I tend to talk off the top of my head.

But let me just open by saying that this is a crucial time in Michigan for PURPA issues. I was at the Michigan Commission for six and a half years and during my tenure, we only had a few, albeit important, PURPA-type cases, but they centered around specific avoided costs' issues.

The Michigan Commission, I understand, like, many commissions across the country, has never had a systematic routine updated Avoided Costs Schedule for rates, in terms of service. So I do my share of mea culpa, but I didn't do that when I was at the Commission either.

But it is a crucial time because certainly in Michigan and across the country, what you're seeing is long-term contracts. In Michigan these contracts with the QFs have been in place for decades, some actually -- one in particular, a hydroelectric facility -- has PPAs dating back to the 1920s.

So long-term contracts, I want to start and end by saying, at least, from Michigan's small QFs, 20 megawatts and under, with whom we work, these are a diverse set of QFs, hydro biomass, landfill gas, almost all of these are very low-cost, compared to the utilities' rates, most significantly lower than the utilities, even commercial, industrial or residential rates.

So they are low-cost in Michigan. But let me just say that I just picked three particular questions that the Commission has asked to hit on, in my opening comments here. Most of the facilities again, with which I am referring, are 6 megawatts and under, yet they're very important, especially to the local communities in which they serve.

And again, my comments really center around existing facilities. These facilities have been on the utilities' systems for decades. I understand there's quite a bit of talk about a new explosion of PURPA, especially out West, but from my perspective, I'm really trying to focus on my discussion on existing facilities that have been there and operate within the local communities, with which they serve.

So first let me make a couple of comments on the question about whether the Commission should continue or Congressional law should continue with the rebuttable presumption that the Commission has adapted, in terms of Section 210(m)'s requirement that QFs 20 megawatts and below do not have nondiscriminatory access to competitive organized full-sale markets. And that there continues to be barriers to access for these smaller facilities.

I can't stress enough -- I think there's some assumption, at least in my vantage point, that since MISO is an organized market, that that's just fine for energy and capacity needs for these QFs. And if I can leave you with no other thought today, it's that nothing could be further from the truth.

Because most of the states within MISO are fully regulated, MISO's markets have never been designed to be long-term markets in the sense that they ensure long-term resource adequacy needs. And consequently, obviously they would not fully compensate or fairly compensate QF generators for their resource investments.

As MISO has recently stated in a certain regard, "The current market will continue to provide only a balancing function and will fail to efficiently support resource investment decisions in those areas of MISO that rely upon MISO's marketplace signals for those decisions."

Allowing utilities to require QFs in Michigan to utilize the MISO market, either directly or indirectly, by trying to set new avoided cost rates based on energy and capacity from the MISO market, is essentially getting through the back door, what those utilities cannot get through the front with your requirements that they obtain waivers to require market access.

I want to just jump ahead and give a couple thoughts on the "must purchase" legal requirement obligation and how, again, important it is to these facilities in Michigan. Without that mandatory purchase obligation of these existing reliable, renewable resources, quite simply there is no incentive for incumbent utilities to contract with these renewable resources.

And that's simply because they have an advantage, especially in Michigan, with rate-of-return regulation to build these facilities themselves. So whether you're talking about solar, wind, they make improvements to their own hydro facilities on rate-payer dollars. And yet, they seek to require the smaller QFs in Michigan to utilize this underpaid MISO market.

Let me just end with four examples --

Let me just say, local communities in Michigan, mayors that we've been speaking with and working with, I know our focus is on customers, but also I just want to impress that these existing facilities provide tax base, water lake levels and other ancillary benefits to the local governments and local areas in which they operate. And I think it's just important to keep that in mind as we're looking at just avoided cost rates and mandatory purchase obligations. With that, I'll close, and thank you.

MS. SIMON: Allison.

MS. CLEMENTS: Thanks, Julie. Thanks, Chairman, Commissioners and staff for including us today. My name is Allison Clements and I represent the sustainable FERC Project, which is a coalition of national and regional nonprofit environmental organizations focused on removing federal regulatory barriers to our community's clean energy goals.

We advocate before this Commission and also in the regional transmission organization areas of the country and increasingly in regions that came together pursuant to FERC's Regional Transmission Planning Rule, Order 1000. We appreciate the opportunity to comment today.

Our member organizations are located across the country and so we have a perspective of FERC's PURPA implementation from both organized and unorganized regions connected to our policy perspective. It's a really great moment for the Commission to stop and assess how PURPA implementation is going.

The grid is changing. We know that. Base-load, thermal, traditionally dispatchable power is no longer the only game in town. And when we think about modernizing PURPA, we want to make sure we continue down that path of that grid evolution that we're already on.

Renewable energy costs are decreasing. Customers are empowered and want to see renewable energy development. And excitingly, PURPA is starting to work on that specific front, although it's been working in a lot of important ways historically.

We have already heard the historical references to 1978 and Congress' passage of PURPA with two goals, both getting off of fossil fuels and getting on renewable energy, energy efficiency and cogeneration. And also importantly, a second distinct goal of increasing competition in the energy sector, and we know that PURPA has played a foundational role in the development of the independent power sector. PURPA has proven capable of Congress' intent, but it has not yet run its course.

In preparing for today, I thought it would be worth opening with a couple of points about renewable energy and public policies as they relate to PURPA. First, the fact that state RPS standards exist in twenty-nine states, and the fact that there are federal and other state policies designed to drive towards various types of clean energy, does not negate the specific purpose of PURPA.

The interconnection right that comes along with PURPA's requirements, the mandatory purchase, FERC's mandatory purchase obligation and other pieces, make PURPA's intent distinct and even to the extent that these other policies are succeeding in practice does not mean that we should be relieving utilities of their obligations under PURPA.

Second, to the extent that these policies are succeeding in bringing down the prices of renewable energy resources again, it does not mean that we are done with PURPA. There is an idea about who's going to produce this renewable energy and whether or not it's going to get on to the grid that remains important.

Congress reviewed the statute in 2005. At that time, seventeen states already had renewable portfolio standards or renewable portfolio goals. So this was not something that wasn't known to Congress. The changes did incorporate the reality of changing wholesale energy markets, but the changes did not say, "Okay, we've got state renewable portfolios entered, we no longer need PURPA as it was."

Last year, in 2015, 4.7% of our country's electricity was generated by wind power and less than a percent was generated by solar power. So we still have a long way to go. In some states, PURPA is the only way, by which renewable energy projects get built. And even in the states where that's not the case, it remains a critical component of allowing for smaller, independent renewable energy generators to compete.

We hope, as a coalition, that FERC will update its PURPA regulations to recognizing the continuing changes that are taking place on our electric system, but not to jump too far ahead. There are opportunities to issue guidance or regulations that will protect qualifying facility's opportunities to continue to provide clean energy to our system.

I hope to speak specifically to the 20 megawatt and below rebuttable presumption, as well as utility contracting practices vis- -vis potential qualifying facilities, and the potential of the energy imbalance market.

And my last comment related to the mandatory purchase obligation is when we talk about considering the need. The need for these types of resources. We need to start from where we are today in 2016 and not from where we were in 1978, and in that case, public policies are incorporated into utility planning, into regional transmission system planning, almost as a matter of course now.

And so thinking about the availability of QFs should be something that's incorporated into utility and regional planning processes from the start. And that ensures that this great avoided cost opportunity that is intended and continues to protect consumers, will continue to do so. Thanks.

MS. SIMON: Thank you. Todd.

MR. GLASS: Good morning. Chairman Bay. Commissioners. Commission staff. My name is Todd Glass. I'm a lawyer at Wilson Sonsini Goodrich & Rosati and I'm appearing on behalf of the Solar Energy Industries Association. I've been a lawyer for more than twenty-two years, not quite as long as Jerry, but someday I'll get there. Before that, I worked at Washington Utilities & Transportation Commission.

I am very happy to participate in this Technical Conference today in defense of PURPA and its implementation. On the side, I teach energy project development finance at UC Berkeley School of Law. The number one class after the intro class is Power Purchase Agreements.

Why? The Power Purchase Agreement is the single most important contract of the development and financing of an energy project that's not owned by a utility. Without the long-term commitment to buy the output of that agreement at a fixed price, there is no predictable stream of revenue. Without a predictable stream of revenues, there is no financing. Without any financing, there is no project.

The next class that I teach and the first law that I teach is PURPA. Why do I teach PURPA? PURPA is the genesis of independent power in the United States. It was the first opportunity for entities to compete with vertically integrated monopolistic utilities. They didn't want to do it. Congress forced them to do it in 1978.

PURPA's key elements from the "must purchase" obligation to the avoided cost to the interconnection and wheeling to the regulatory exemptions were key to building an independent power community. And it became, as the Commissioner stated, the foundation upon which EPACT 1992 was developed, Order 888, and a lot of things afterwards.

It was these fundamental elements that started in PURPA that has changed the United States' electric grid and entered this competition. Well, back in my day job, for the last ten years, I've developed and financed hundreds of solar projects, ranging from KWs all the way up to several hundred megawatts. I can say that developing and financing of these projects is getting harder.

Both utility scale in the 2- to 20-megawatt is getting harder. Why? PPAs are getting hard to locate and execute. Renewable portfolio standards, that have been referred to, are largely filled up in those twenty-nine states that were referred to.

The clean power plant is stalled and the projects that are getting financed today, that I'm glad to see is happening, largely got started several years ago. And that the future does not look quite as rosy for long-term purchase agreements.

Why? Utilities are also getting more and more difficult to deal with, especially if you're a QF attempting to interconnect on the distribution grid. There is an unwillingness to honor legal enforceable obligations. There is RFP abuses. There are unfinanceable PPA terms that the market power, the utilities used from the terms, the curtailment terms, security requirements, various avoided costs games are being played, as well as very difficult and discriminatory interconnection processes.

I appear here on behalf of the Solar Energy Industry and SEIA, which represents a 1,000 member companies across the United States, and we champion the development of this solar, clean and affordable solar energy, after removing market barriers.

SEIA represents all members of the value chain and of the 29 gigawatts that have been installed in the United States, just 7.5 were installed last year. We're accelerating this type of growth, and we expect in 2016 alone to have an additional 14.5 gigawatts installed. Most importantly we employ now over 210,000 people in the United States who are actively involved in the solar industry.

So what does SEIA want? And why am I here today and what do I want to talk about? First, FERC, the Commission should make sure that PURPA is being implemented in a manner consistent with the legislation and the regulation. Most specifically, I believe that the Commission should establish clear guidance on what a minimum set of contractual commitments should be as part of the LEO and the Power Purchase Agreement.

We mean fixed prices, a long enough term, strict guidance on allowable curtailments, equitable security requirements, changes in law and other regulatory disallowances should not be allowed to vitiate the contract and other mechanisms to deal with interconnection and transmission issues.

The second one is, I think you should do no harm to the nondiscriminatory access to the market. And in particular, the mandatory purchase obligations.

Third, we should -- I suggest that the Commission consider establishing a limited and efficient form for QFs to bring matters to the Commission where the utilities' abuse of contracting practices are harming the development.

And finally, and most importantly, I think you should honor the goals, the statutory goals of PURPA, which I didn't hear today from the utility perspective here, but it is to encourage the development of cogeneration and small power production. And to eliminate the discrimination that those entities were feeling with respect to interconnecting prior to 1978. Those matters are still facing the distributed generation solar industry today. Thank you.

MS. SIMON: Thank you. Bob.

MR. KAHN: Greetings. My name is Robert Kahn. I represent the Northwest & Intermountain Power Producers Coalition. Thank you, Mr. Chairman, members of the Commission and staff. We very much appreciate this opportunity to speak to you. Let me just from the very top, agree with Todd Glass' very specific proposals to you. I can't endorse them heartily enough.

And I'm doing so as an advocate for competition, because fundamentally what our group, known as NIPPC, is all about, is promoting the competitive paradigm, I call it defending the paradigm, which FERC has done a superb job of promoting. Fact is, is that FERC in at least our world in NIPPC, is not a four-letter word.

We're here because PURPA is the keystone of our industry. PURPA is about competition. It enabled competition. And the reasons why the industrial-owned utilities have opposed it as long and as vigorously as they have and are doing so today is because it enables competition.

There are several claims that have been made along the way that I'll like to address. But to reinforce again, Todd Glass' testimony just now, we have over eighty cases that have appeared, PURPA cases, that have appeared in Idaho, Oregon and Washington. We list them as an attachment to our written testimony, and there are many more that could've been litigated at the Commissions if the developers could've afforded to do so. So this idea of having an expedited treatment, or at least hearing at FERC, might be really a good idea for all concerned.

The truth is, is that the Commissions, at least in our experience, as we put it in our written testimony, have a genuine disinterest in PURPA, which is rather kind, frankly it's been a root canal for them. I think that Travis Kavulla's comments to the effect that the Montana Public Service Commission spending 25% of its time on PURPA is a problem in and of itself.

We shouldn't be having these fights, but we do. And that's because, as we mention in our testimony, there is outright hostility on the part of the IOUs to what we're trying to accomplish. Now let me be clear. NIPPC advocates for what we would call the "City on the Hill". We advocate for organized markets in the West.

We have done so progressively and hopefully constructively for a really long time. We're not there yet. The claim that the energy imbalance market, which is, if you will, a precursor to an organized market, it somehow makes PURPA irrelevant, is just nonsense.

No IPP is directly connected to the IM as I appear today, and there is no prospect for interconnection or intertie bidding or any of the necessary steps that would get us into that market. So claims to that effect are to be kind of misrepresentation. And the claim that we have competitive procurement rules at the utility commission level is really just sad.

We have fought for those and we have participated in designing them. And NIPPC has litigated and represented our industry's interests within the context of competitive procurement rules, and then, for example, the State of Oregon, over the last ten years, under what was considered to be model competitive procurement rules, our industry has only developed 5% of the total capacity added to serve rate-payers in Oregon.

So we have a problem here. And PURPA continues to be the keystone or the last resort, if you will, to preserve the option of competition. Let me just end here. Our industry, over the years, has added value, because frankly we spend our own money. And in spending your own money, you're much more careful about what you do for investments and what you do for innovation.

Utilities can do the job of distributing power, of maintaining reliability on the system, but they do not have as PURPA recognized, unique capacity to develop generation. On the contrary, we'll do a better job, we have done a better job, and we'll continue to do a better job as long as PURPA is enforced, as you have historically enforced going forward.

Final word please. The idea of cooperative federalism, which is an underlying element to your relation to the states, is a two-way street. It should not be some kind of pablum that substitutes for your tradition of enforcement of PURPA as defined by Congress. Thank you for your time.

MS. SIMON: Thank you.

MR. KJELLANDER: Thank you. My name is Paul Kjellander. I'm with the Idaho Public Utilities Commission. Again, like everyone else has said, thank you very much for the opportunity to be here today. And I certainly applaud the Commissioners' efforts to sit through what promises to be another day of bun-numbing fun.

Where I'd like to start is with a snapshot of Idaho's renewable activity, as well as its PURPA activity.

Our largest electric utility, Idaho Power, has almost 1,300 megawatts of renewable energy under contract, of which approximately 1,100 megawatts are PURPA contracts. Now this is significant when you consider that Idaho Power's minimum system load is 1,100 megawatts.

The cost to customers for that 1,100 megawatts of PURPA over the lives of those contracts represents 3.75 billion dollars, so these are not small projects and there is a commitment on behalf of this Commission, the Idaho Public Utilities Commission and the utilities to get PURPA into the system. With that said, the Idaho Commission is not anti-PURPA and we're not anti-renewable.

The real issue that I want to bring to your attention today is with disaggregation, or gaming of the system of PURPA. The main problem that we see with this is that large-scale projects have essentially broken up into smaller projects for the sole purpose of gaming PURPA.

The most blatant example of the developer breaking up a large-scale project into multiple purpose-sized projects occurred in Rocky Mountain Powers' Idaho territory. In this instance, the developer initially bid a 150-megawatt project into the utilities' RFP process. When the developer failed to win the bid, the project was recast as five separate PURPA projects.

The output of this reconfigured utility scale windfarm clearly exceeds the spirit of the 80-megawatt threshold at PURPA's higher end and it clearly breached the intent of Idaho's published rate limit of 10 average megawatts delivered. Rocky Mountain Power estimates that this disaggregated project will cost its customers 1.1 billion dollars.

When we look specifically at disaggregation in Idaho Power's territory, we see 183 megawatts of power from four developers who are broken up into sixteen projects that are under contract today. Regarding the projects that didn't go forward, had they been built in Idaho Power's territory, customers would today be paying an additional 1.7 billion dollars.

The other issue that I want to touch on is disaggregation in Oregon. Our disaggregation concerns stretch beyond our own borders of Idaho. A recent series of projects approved in Idaho Power's Oregon territory are raising some concerns. The Oregon Commission approved six PURPA projects that require Idaho Power to take 60 megawatts of power from six solar projects. The average load for Idaho Power's Oregon territory is only 98 megawatts, which makes it very hard to argue that that power is needed.

The disturbing similarities among these six projects include the same operation dates, the same project size, the same terms and payment conditions, the same developer and the same solar panel manufacturers. This looks like a disaggregated project that stretches the spirit and intent of PURPA.

The problem these six projects represents for Idaho is that under the current allocation scheme, 95% of those costs for those projects will be recovered by the utility's Idaho-based customers. That's almost one billion dollars over the lives of those contracts.

Unless the issue of disaggregation is addressed, there's a pretty good chance that we could be facing an ugly border war with the State of Oregon. What I would hope for, as far as a path forward, is that the Commission could look specifically at the disaggregation issue and give the State some more immediate tools that it can deploy, so that when we recognize that disaggregation is occurring, we can address it in its time and place because as we've seen it today, we have 1,300 megawatts of PURPA in our system today, and it's not cheap.

And when we see disaggregation, when we see that the intent of PURPA is clearly being sidestepped, it would be nice to be able to address it before it has a significant financial impact on customers. With that again, thank you very much for the opportunity to be here and I look forward to participating.

MS. SIMON: Thank you. Irene.

MS. KOWALCZYK: Good morning, Commissioners and FERC staff. My name is Irene Kowalczyk. I'm the Director of Global Energy for WestRock Company, the leading manufacturer of packaging products. I'm representing the Industrial Energy Consumers of America, the association of leading manufacturing companies with over one trillion in sales.

IECA represents industrial energy consumers in every industrial segment of the economy. My comments today will focus on QFs that are CHP units or cogeneration units, the subset a very efficient and environmentally helpful source of power.

I wanted to note that the manufacturing sector builds CHP systems to provide economic steam and electricity to supply the manufacturing facility. We're really not in the power generation business. We're in there to produce products.

DHP systems are vastly different from other QFs because they must integrate the thermal and power production into an industrial process. We are concerned this Conference may result in FERC revisions to rules implementing PURPA that may effectively dismantle many of the necessary protections that PURPA provides to QFs without a change in law. And we would highlight that many of the concerns that have prompted this Conference are not applicable to industrial CHP facilities. We'll highlight the differences between CHP QFs and other QFs.

PURPA is just as important today as it was in 1978. Without the regulatory assurances of PURPA, significant energy conservation efficiency and greenhouse gas reductions achieved to date would not have occurred. With regard to some of the questions that were put forward to the panelists, as far as the "one-mile rule" is concerned, that was just discussed, and disaggregation, this is really not our issue. However, if there are PURPA abuses, then they probably should be addressed.

We support the continuation of the rebuttable presumption for facilities 20 megawatts and smaller. The volume of power that typically moves to the grid from these manufacturing CHP facilities is so small that it would be a significant administrative and cost burden to become a market participant in the organized markets.

The most logical off-taker is the local utility that can easily integrate this as available power into their mix. One point that we would like to encourage the FERC to change the basis upon which QFs that our CHP units end up in the over or under 20-megawatt category, so that it's based on the maximum amount of power that can reasonably be exported to the grid under normal operating conditions, rather than on its net generating capacity.

With regard to curtailment, QFs at our CHP should be the last in the queue of QFs to be curtailed, and only in emergency conditions where grid stability is threatened. This is because the CHP is tied to an industrial facility that has tremendous economic value to the communities in which they are installed.

Also, CHP facilities should be curtailed down to a net zero export condition so as to not drastically impact the efficient operation of the manufacturing process and this is if you have to have the curtailment, if everybody else is off the system and you are at the point where you're looking at the QFs but our CHP brings them down to net zero only so they can continue to run their plants efficiently.

On interconnection, CHP facilities should not be treated just like merchants and utility power plants in the interconnection process. The existing rules fail to reflect the unique operational characteristics of QFs that are integrated into an industrial process. IECA recommends development of streamlined interconnection process for CHPs and waste heat recovery QFs.

We support preserving the obligation to purchase "as available" power and to provide supplemental standby and maintenance power at reasonable rates. Discrimination in this area still exists today and you've heard from others that have said that.

On the imbalance energy market's issue, we believe this is not a viable substitute for fully functional Day 2 energy market. This is because they're largely illiquid and not transparent. A CHP QF selling "as available" power into really an imbalance market would not be able to do so easily without subjecting themselves to significant financial penalties and that's even if they can get interconnected.

And last point we would make is that energy imbalances caused by renewable QFs can be a problem because utilities, the RTOs and the ISOs, they have to fill the voids caused by that resources' intermittency and we've heard cases of the utilities needing to really dispatch their gas units to fill the voids caused by some of the renewable intermittent power that's on their system and that can cause them running their units less efficiently. However, CHP QFs are not really contributing to this problem. Thank you.

MS. SIMON: Thank you. And we move to Mr. Schmidt from that side to this side.

MR. SCHMIDT: Good morning. I'm Joel Schmidt, Vice-President of Regulatory Affairs at Alliant Energy. We are a mid-West transmission dependent energy company serving customers in Iowa and Wisconsin. I thank the Commission, as my fellow panelists, for the opportunity to participate today on behalf of the Edison Electric Institute, EEI, to discuss the market issues and timely reform associated with PURPA.

Our commitment to deploying cost-effective renewable resources is strong as an industry. EEI members support the deployment of renewable resources and are leading the way in renewable investment, delivering virtually all of the wind energy and the majority of installed solar capacity.

From Alliant's perspective, since 2008, we have invested more than one billion in wind energy alone and have been delivering cost-effective wind resources through purchased and owned facilities for our customers for over two decades.

We are proud Iowa's the national leader in wind energy deployment, deriving 31% of the state's electricity from wind. Although our EEI members operate in significantly different market structures, we are all subject to PURPA's mandatory purchase requirements.

Two-thirds of the U.S. energy market is now served by wholesale regional electricity markets. As such, PURPA's QFs have ample opportunity to bid renewable energy into the wholesale markets through competitive processes. Despite this access to wholesale markets, many QFs choose to develop projects under PURPA's mandatory purchase obligation, often at a premium, to other available renewable energy resources, such as utility-owned or competitively-bid PPAs, with that premium being borne by our customers.

To facilitate this discussion, in recognition of the changes in the markets and the generation fuel mix, my written statements propose timely changes to FERC's regulations to highlight the issues there being seen in the markets today, and to propose changes to the Commission's rules and regulations to address potential market abuses.

I would like to focus on the need for changes to FERC's "one-mile rule". Alliant Energy's Iowa service territory, a single wind developer has partnered with two large foreign-owned companies to violate the spirit and intent of PURPA, which was designed to truly help local renewable developers with no access to competitive markers.

Specifically, this developer for essentially one 58-megawatt project has grouped two foreign-owned projects into separate corporate entities, each with a 2- to 3-megawatt wind turbine located just beyond the one-mile FERC-designated limit from each other to qualify its individual projects under PURPA, as well as for Iowa State tax credits.

This cumulative project far exceeds the maximum QF size limit of 20 megawatts for organized markets. This behavior negatively manipulates Alliant Energy's customer costs and reliability. It also highlights why changes are needed to FERC's "one-mile rule".

Now, moving to customer costs. Current market-based wind prices are approximately 25% lower than the PURPA obligation prices we are forced to pay for this wind power. As a result, from the project I discussed, this will cost Iowa's Alliant customers incrementally 17.54 million over ten years.

The purpose of our proposed regulatory changes to the "one-mile rule" is to increase transparency, improve renewable resource integration and allow electric utilities to bring alleged instances of gaming and market abuses to the Commission's attention for consideration and resolution before allowing such resources to be granted QF status and burdening our customers for years.

Our revisions, if adopted by the Commission, will benefit all stakeholders in the marketplace by providing greater transparency and fair rates for all to achieve the objectives of cleaner, more reliable and more affordable energy today and into the future. In conclusion, thank you for the opportunity to participate and I look forward to the dialogue.

MS. SIMON: Thank you all for those opening statements. I'd like to turn to Chairman Bay if he has any questions for any of the panelists?

CHAIRMAN BAY: Thank you. I appreciate the comments of all the panelists, and for the panelists who have been supportive of PURPA, what would be your response to the concern raised by several of the panelists regarding the gaming of the "one-mile rule"? I'd just be interested in hearing your response to that concern.

MR. KAHN: Chairman Bay, this is Robert Kahn with NIPPC. My response is that this is a manageable issue. The Commissions themselves have addressed it. I'm not sure that it requires FERC action to manage. In my view, we can talk about it, but it's not the kind of thing that cannot be resolved. It's more a manageable issue than has been made out to be.

CHAIRMAN BAY: And how have State Commissions addressed that particular issue?

MR. KAHN: Best to ask our Commissioner to my right.

CHAIRMAN BAY: Okay.

COMMISSIONER LAFLEUR: Go ahead.

MR. KJELLANDER: I think that I have to disagree with the fact that the "one-mile rule" is manageable. I think even when you try to extend it to five miles, which our neighboring State of Oregon has done, we still see manipulation of the system, and with solar technology, it's even easier to separate those projects because in, at least my part of the country, we have over 300 days of sunshine. And we have a lot of high-plains desert, a lot of area in which you can locate those projects and separate them by whatever mileage separation you would want to deploy.

As far as a direct answer to your question, I think in utilizing PURPA, every instrument that we have within the Act that was written in '78, is a very blunt tool, and when we look at the tools we have, we have project size, we have the ability to set the avoided cost, which, if it is a long-term contract with a forecasted price component, we'll always be wrong, and we've seen it to always be wrong in favor of the developer and against the consumer.

Then the last one is that essentially the contract length. And so when we have those as the three blunt tools, it's very problematic. And that's why, with the issue of disaggregation, it'd be very helpful to get some additional guidance from the federal level, to give us the tools to act a little bit more immediately when we see some of the issues that clearly spell out that this is a disaggregated project and in my written comments, I've laid out quite a few bullet points that I think, at least, help encapsulize some of my thoughts in that arena. And thank you for the question.

MR. KAHN: Yeah, I think that -- to be more specific, look. You've got ownership that you can distinguish. You've got your interconnections that you can distinguish. To say that this is easily gained is to underestimate the capacity of utility commissions to cope with the problem that they can cope with on their own turf.

To elevate it up to make it a FERC problem, I think, is generally an overstatement. You know, this is a matter of obvious interest over time, but frankly, to put it into context, it's what entrepreneurs will do as they're trying to add to the system and to make a buck. So this is manageable, and I think it's a bit of a red herring, frankly.

CHAIRMAN BAY: Clearly, there is a tension here, because the point of PURPA was to encourage the development of these other resources, and so for those of you who think that this rule should be re-examined, the "one-mile rule", what would you propose as an alternative that balances the objectives of PURPA with your concern that the rule is in some way being gamed?

MR. SCHMIDT: Thank you. I'll refer briefly to my written comments, and there's some other written comments out there, but I think to summarize them would be really reconsider and provide that clarity and guidance, either through the FERC processes or to the State Commissions of really, what is one site? What should be considered?

I think we all know, as was referred to between the technologies and between our jurisdictions, one mile's very subjective. One mile in northwest Iowa, in my distribution system, is much different than one mile in my most populated city. Or on the outskirts of that load center.

I'm sure it's much different in our neighbors to the west, so I think it's really -- move forward and say, what are the factors that should be considered and how can we timely get to decisions so all the players in the marketplace can move on and move towards that cleaner energy that's needed, and have it integrated into the system.

CHAIRMAN BAY: Anyone else?

MR. GLASS: Quickly. I would agree with getting clarity, because developers don't want to develop projects where they can't develop projects. They want to develop them where they can and where they can avail themselves of the rights in the PURPA.

I would say to the Commissioner, however, the fact that you find that avoided cost rates tend not to be the lowest possible rates over time, that's part of the architecture of PURPA itself, and I believe that we were instructed not to start trying to revise the statute today.

CHAIRMAN BAY: Anyone else?

MS. CLEMENTS: Yes, Chairman, and just lastly, I actually agree with all of these comments, but just would say as with most things that FERC does, obviously guidance is helpful to states and participants. So overall, looking at that and giving proper guidance, especially for new facilities, would be helpful, but just keep in mind as with things that you do, fact-base is also very important.

So again, we represent a certain facility I'm thinking of that's been on the utility system for decades, and it's separated by a small river. It's been there for forever. So that's an existing facility, so first just do no harm to those facilities that are otherwise not questionably gaming anything and are just existing within that one-mile vantage point.

CHAIRMAN BAY: Joel, it sounded like the approach that you were raising would be more open-ended looking at a number of different factors, but wouldn't a concern with such an approach be that it would lead to a fair amount of uncertainty for developers?

If you had some sort of open-ended approach where every single PURPA application had to be reviewed under this multi-factor approach, wouldn't that really cause a lot of uncertainty? And so, isn't that one of the benefits of having a test that turns on some sort of bounded geographic distance?

MR. SCHMIDT: I agree that uncertainty is not good for anybody involved, and I think other panelists have noted that. I think you've actually identified the issue. We probably don't want to be at one or the other of the polar extremes, and I think we need to really think about that, keep it to relatively limited and -- it's almost, put some common sense to what is a site, and have that out there.

And as much as I -- we would encourage as much as can be kind of local circumstances, be that geography, be that grid systems, be that the technology, be that the financings in that area. Be if it's local or others, but that can be incorporated, so that is going to be the fine balance, because if you get too prescriptive on it, it will provide more uncertainty.

But I think right now, there is significant uncertainty as this stuff comes through. And frankly, a lot of angst that probably can be avoided with a bit of guidance.

CHAIRMAN BAY: All right. Thank you. Cheryl?

COMMISSIONER LAFLEUR: Thank you all for those comments. It really was striking to me how far PURPA has come, listening to this. And also I heard echoes of our conversations yesterday about the mismatch between where good opportunities for renewables are, sometimes in population centers and transmission and all of those good things.

When PURPA started, of course, the concept was these huge, behemoth, vertically integrated utilities and these little QFs that needed support. The thought that anyone would ever be drowning in PURPA power was the farthest thing from anyone's mind. So for those of you who have spoken and quite compelling about the need to continue PURPA as it has been, I'm interested in theoretically whether there's ever such a thing as too much.

If we hypothesize an unnamed state with huge renewable opportunities and very low population, do they have to take up to their total load? Above their total load? I mean, is there any theoretical maximum to the PURPA obligation in your mind?

MS. CLEMENTS: Commissioner, that's a great question and I think some of the changes made in 2005 get to that question. There's a couple of important points there. One is that if there are true organized wholesale markets with opportunities for long-term purchases that make projects financeable, you can get the waiver from your obligation.

In the 20-megawatt and less rebuttable presumption, in organized markets, it's just that it's rebuttable and you have on one occasion, at least, determined that the presumption of nondiscriminatory access was incorrect. And so I think -- otherwise, we're not seeing this perfect storm of factors that are leading to that drowning in PURPA power, because we have long queues.

But the reform pieces, in terms of utility practices, the utilities are pushing back because we're starting to make progress. And so the question now is how do you rearrange those pieces to make it more fair for everybody?

COMMISSIONER LAFLEUR: I was thinking more about the bilateral markets. I know you call them unorganized, but we usually say bilateral.

MS. CLEMENTS: Sorry.

(Laughter.)

COMMISSIONER LAFLEUR: Thank you. Bob?

MR. KAHN: Yeah, so this is Robert Kahn with NIPPC again. Yeah, they're pretty unorganized. They really are. First of all, just for point of fact. The idea theoretically we could speak to, but in terms of this being imminent reality, I have to say there's been some fast and loose number crunching here.

Just to point a fact. The nameplate QF capacity factors don't match up with the average electric use, and in one of the testimonies made today, at least the written testimony, there is a mismatch on capacity and megawatt hours. It's not okay.

Also, we have to be clear that when we're dealing with a multi-state utility like PacifiCorp, where are we assigning the PURPA use of that power? It's maybe calculated as available PURPA QF capacity across its system, but if it's shrunk into just one state, it is going to look like a flood, but it really isn't.

In terms of the theoretical concept, from our point of view, if it's cheaper for rate-payers, which it historically has proven to be in Idaho, notwithstanding the comments by President Kjellander. We can document that if you like. It's cheaper since 1978 up to the present, compared to the operation of Idaho Power's system.

So, in other words, if it's in the advantage of rate-payers that PURPA projects be operating, I'm not sure what the problem is. I mean, clearly, historically, we've looked at it as a function of marginal costs, but on more than a few occasions, utilities will advocate for defining avoided costs as the operating costs of the system.

So they can have it both ways. Truth of the matter is, is that if we can beat them, we should be beating them, because it's in the rate-payer's interest.

COMMISSIONER LAFLEUR: You got everyone's attention starting with Paul, or President Kjellander.

MR. KJELLANDER: Paul works well. We can

quibble over numbers and I guess that's what we do in the context of cases in front of the Idaho Public Utilities Commission and I guess we'll continue to quibble over numbers and that's what the process is about, and I appreciate that robust nature of the conversation today.

But with regards to the pricing piece, I know there's a panel this afternoon on avoided costs and I know that Commissioner Kristine Raper is more than prepared to addressing with those issues, so as you move on through the day, I think she can touch on quite a few of those things with the impact of the avoided cost scenario, that she's seen both as an attorney, and now as a Commissioner. So with that, then again thank you.

MR. GLASS: Thank you. A few additional ideas. First one is to the point -- the rebuttal presumption provided in EPACT 2005 and beyond does provide a relief valve. I don't believe that any utility has gone in and successfully said that the 2- to 20-megawatt QF projects have access to the market. Nobody's ever done it. They haven't proved it. So we shouldn't have a rule-making that --

COMMISSIONER LAFLEUR: But that wasn't what I was talking about. I was talking about in the bilateral markets.

MR. GLASS: Definitely not in the bilateral markets. The second one is that I do believe, as President Kjellander suggests, the answer is potentially in the avoided costs, and I also think that in your light-loading curtailment provision, which is 18 CFR 292.304(f), if you start sending the signal that the utility is going to curtail, because the systems are not able to take on, all of these things the developers will respond to, they will not be trying to develop projects where they're facing curtailment under the regulations where they're not getting the avoided costs that make sense, and whether where they can't avail themselves due to the rebutted presumption.

COMMISSIONER LAFLEUR: Thank you. Jerry?

MR. BLOOM: I think your question is great, but I'd like to change your question where it says rather than how much, I think the real question is, is how is it managed? And Todd just started hitting on this. I think that's the real issue. And if we look at -- first, I just want to go back to my opening statement and say, again, you're not hearing anything that CHP is the problem here. And we really need to keep that in mind as we go through this in terms of how much CHP has put on the system and those needs as critical.

The second thing is, when I go to the idea of how it's managed, there are plenty of tools and mechanisms and frankly, the rules and the regulations that are in place to manage that, in terms of one, as Todd just hit, the curtailments. As we proceed through the terms and conditions, I'd go into the modernization of these contracts with the utilities. Utilities are asking for curtailments.

And one of the things, for example, we've worked away from, which is inherent in the FERC's rules and, in terms of capacity and energy payments -- if, for example, renewables were getting a capacity payment, they could offer a large amount of curtailment would be possible, because their whole revenue stream isn't energy only.

There's all kinds of tools, so it's, in terms of the implementation of the terms and conditions within the contract that can use the control and to send the market signals. And I think that that's, in terms of the solicitations and what's being looked for, it may change the nature of avoided costs and how you define that.

But there's a lot of talk about overpayments, but I just want to say it's so -- if avoided costs is being done properly and correctly, there aren't going to be overpayments and I agree with comments that have been made. If you historically look at the claims that are made, versus what the payments have actually been, in terms of real capacity in additions what's avoided over and over again, those claims don't hold up in terms of --

I think that we have all the tools in place to manage this, and then we don't have to decide who's in and who's out, but how do we manage as these resources come onto the system?

COMMISSIONER LAFLEUR: Joel?

MR. SCHMIDT: Okay, though I probably could talk about access curtailment and avoided costs and would be more than happy to -- I do want to go back to the question about what is too much. I think there's really two components I'd like to point out in that. There's really two parts of that.

One is where -- and it's not all of a sudden you're redlining. I guess, back to our 1970s, I wasn't born in the '70s, but I was a child in the '70s, and some of the first driving I did is with tachometers and you talk about redlining. Well actually now, with having gone through teenage drivers, I now worry about when you get to the top of the green line, start moving to the yellow and to the red.

And I think that's really what we have to look at. And we also have, for us that have the obligation to serve these customers, it gets down to a circuit level. And I think there's a lot of discussion and I think guidance and help from FERC, as well as the state commissioners on siting helps everybody, because when you really think about the two types of generation that have been primarily talked about, solar and wind, they have not had to go through the historic of where siting was really a major impetus into it, and I think we're hitting that maturity stage. So I think it really fits into that.

So it's back to -- I had a mentor of mine very early in my career, when we were talking about materiality -- I'm an accountant by nature -- everything is material to somebody at some point. Everybody's paycheck, everybody's purchase, that's material to some level and I think we have to make sure that we start sending signals and guidance to talk about where the rubber hits the road, which is at that retail customer. Thank you.

COMMISSIONER LAFLEUR: Okay. Kendal?

MS. BOWMAN: Yes, I would like to echo what Joel said. I think that too much of one thing can cause problems, as one of our system operators explained to me. It's like a piece of chocolate cake. A slice of chocolate cake is great, but then if you have to eat the entire chocolate cake, it becomes a problem.

We need to be planning and integrating these resources in a very balanced diversified fashion. We don't want to have all of one type of resource, particularly one that's intermittent. That can definitely cause operational and reliability impacts to your system. It needs to be done in a planned way, not an unfettered push, where you have an endless amount coming online.

COMMISSIONER LAFLEUR: My second and last question. For those of you who have spoken about the need to reform or moderate PURPA, which I guess is Paul, Joel, Kendal, do you see a distinction between combined heat and power and the intermittent renewables that some of the other speakers have spoken about?

MR. SCHMIDT: Yes, and I will admit in our comments, we did not put a lot of attention to that, but having operated systems, as Kendal mentioned, different resources in different places act differently. They provide different benefits, they put different strains on the system.

So I think throughout this, and I would venture to guess, the resources we're talking about now, though, we'll probably still be talking about them in the future, will also be different. Technology, operating practices, customer preferences, life in general will change that.

MS. BOWMAN: I would agree. I didn't spend a whole lot of time on CHP and I will say to Michigan, small hydro, I think is unique. I think PURPA does allow for distinctions between technologies. So I think there is some latitude there to do that.

MR. KJELLANDER: I think Joel hit it on the head instead of the other presenter. With regards to those intermittent resources, when that nameplate capacity hits the system all at once, system operators are scrambling and it's extremely problematic. And so the resources aren't identical and I think taking a separate look at them, to what they are, is fair.

MR. GLASS: One quick follow up. Two things. First one is while I do see from a power flow engineering perspective that CHP is different from solar and wind and the like, I would, one, remind us that PURPA and its regulations, you know, call for nondiscrimination. And discrimination is something that we should be avoiding rather than introducing.

The second thing is, is also think about the unintended consequences. Right now there's a variety of technologies and that's one of the exciting things about what's happening in the world today.

Right now we're talking about introducing storage with solar. And if you, all of a sudden, start to compartmentalize and say, well, these people will get one treatment and solar over here will get -- and wind will get another.

What you do is send signals to the market that will forestall things like solar plus storage. So you need to have a consistent system along the way, so that people will develop towards the value, and I would go back to what

Jerry was suggesting is that, if we get more sophisticated about the market and the way that the values are communicated and paid for in the PPA, you will get to a better system, or a better QF.

If you put a price on capacity, guess what? The developers are going to figure out how to maximum that value. So I would just hesitate to discriminate too much.

MS. CLEMENTS: Just to build on Todd's point. I think when we think about the operations from a liability perspective of these issues, we are now in a different place. And there are a whole host of activities that utilities can engage in to help manage that integration, many of which are not FERC jurisdictional activities, but related to resource planning, sending signals to potential market participants about where it might be a good idea or desirable place to interconnect, etcetera, etcetera.

These resources can provide essential reliability services, so we're kind of sticking in this old intermittent paradigm is a little outdated and I think that we should start from that place.

MR. BLOOM: In case I haven't gotten it through yet -- from your question, Commissioner, you know, yes, CHP is different and I want to go to Todd's last point.

I think again, within the context of the rules and the regulations and the utility and the Commission's ability to create terms, conditions in these contracts, those differences can be accommodated. We're not looking at -- there has to be wholesale changes.

For example, in terms of a CHP unit that's providing grid stability and reliability and providing as distributive generation resource, the function is different. The value is different. And there's nothing that prevents, within the context of that contracting process, for the utilities or the commissions to recognize those distinctions and provide value differently.

So that -- and I just want to go to a point that's been made. I don't want to leave the impression in the room today that these are all just "as available" in terms of CHP. Many of our members, because there are schools or hospitals there, industrial operations that are 24/7 need to be base-load.

So if you have a distributed generation resource, right within the community that's providing RA and grid stability and reliability, and there's going to be base-load. And the more renewables we brought in, the call for the need for base-load, we want to have that dual efficiency, we want to use that gas efficiently.

Different terms and conditions can be and should be incorporated in terms of the contracting process. So it's not a matter of whether you discriminate, but how you use those resources and tailor the contracts to the need and tailor the contracts to -- and that includes the statutability curtailments and all those various things. It's all there already. It just has to be implemented in a more sophisticated way.

COMMISSIONER LAFLEUR: Markets have been evolving to define different capabilities. We're talking about a different tool when we're doing it in these contracts. Last word. Charles?

MR. BAYLESS: My comments, like most others, didn't really focus on CHP. I was mainly looking at the sort of deluge of intermittent resources that have hit North Carolina. And I -- one reason I didn't look at CHP is because I think it's far different. It's not an intermittent resource. It doesn't need -- it doesn't impose the same effects on the grid. The backup generation is not the same. Things like that. Intermittent resources not only need back up they can ramp up quickly. It also needs resources that can ramp down quickly. When it changes.

I'm not really sure that there is discrimination. I think that you have to look at the two resources as differently. They have impacts in the system that are different and you have to, because there's different impacts, you have to evaluate them differently and evaluating impacts from intermittent resources, you're just taking into account those costs. I don't think it's really discrimination to look at those.

COMMISSIONER LAFLEUR: Thank you.

COMMISSIONER CLARK: Just first on this issue of CHP. I think if the sole issue was that we're dealing with the CHP, we probably wouldn't be having a Tech Conference today. Right? I'd be back in my office reading through a stack of notational orders that I've been delaying over the last few days as I've been in this room. And y'all wouldn't be seated in these seats. That's probably not the core of the issue, so I would agree with those folks who've talked about that.

Let me talk just briefly about how I tend to analyze some of the other issues that we've been talking about. Which is -- while I would be the first to admit that not every incumbent utility's motives are pure, in terms of what they may be proposing, in terms of PURPA, there's undoubtedly some special interest there.

I think we should also acknowledge also that not every single PURPA developer's motives are as pure as the wind-driven snow either. I mean there are -- when you have an entitlement, there are incentives to gain that entitlement. And we need to make sure that consumers are protected in that. Which is why I take particularly seriously the concerns that we're hearing repeatedly from state commissions throughout certain regions of the country.

Which is they are the party that's there to protect the public interest and is not necessarily there to protect either of these other interests that might have some sort of vested special interest in the particular status quo or change in the status quo.

So when we hear from State Commissions that are saying, "Look, here are the real costs and here is how projects are being developed because of a rule that the Commission has," I think we have to take that particularly seriously. And I've seen -- and this is a little bit different than PURPA, but I've seen exactly these sorts of games that get played.

We had, in my home region of the country, siting laws that were different between North Dakota and South Dakota. So I think, if I remember right, in North Dakota, you would only have to go through all of the regulatory siting if the facility, a wind farm in this case, was about 50 megawatts. South Dakota it was a 100-megawatt threshold. So what did we have?

We had lots of projects cropping up right on the border, where 49.5 megawatts were in North Dakota, 99.5 megawatts were in South Dakota, and you had effectively, 150-megawatt wind farm that was never sited just to gain each state's regulatory regime.

And though it wasn't impossible to overcome that, you just -- each state kind of figured it out and looked at the rules and regulations that you had and you streamlined those procedures so you didn't have the gaming of the system.

I think most of my questions have been asked and answered, but I'd like to ask one in a little bit different way. For those who've spoken generally in a supportive manner with regard to PURPA, does anyone want to take a crack at defending, specifically the "one-mile rule" or the practice of disaggregation?

(no response.)

Okay. So, that's good. I'm glad we've got some agreement on that. I think we've got agreement on CHP and we may have agreement on that particular issue.

What I would urge, and if anyone's had the chance to think about this a little bit more in the intervening time, since I think, I can't remember if Norman or Cheryl asked it, but if you have any more thoughts on specifically, if you were writing the rule for the Commission, how to address that particular issue, how would you write it? To give us some guidance.

And if you don't have anything right now, please think about it and follow up with some comments. Because I really do think it's an issue. I mean, when we hear about costs totaling potentially in the billion dollars or more over relatively sparsely populated states, it's a big enough deal, I think, to get our attention. President Kjellander?

MR. KJELLANDER: Thank you, Commissioner. On Page 6 of my filed comments, there are a series of bullet points that I think touch on a lot of what you're trying to get to, in terms of what needs to be addressed, and how they might be addressed, in terms of the disaggregation issue. I won't go through those. There's probably about a dozen or more. And I think those are probably a fairly decent starting point as you start to look at that issue and again, thank you.

MR. GLASS: Since he brought up his bullet points on 6 and 7 of his pages, I would say this. That when looking at the "one-mile rule" you don't want to eliminate the value of economies of scale. While, of course, we don't want abuse and nobody in the solar industry is here before you today saying that we want to, you know, play games or abuse the rules, the "one-mile rule" or whatever it will be.

On the other hand, we do want to develop enough projects and more projects so that the costs come down. So I would not want to forestall successful developers for doing more than one project in the state. Or gaining the economies of scale of having economy PC developer, you know, contractor, or doing some of the other things, because this is actually what you want to bring down the costs of solar and other things of that nature.

So just be mindful that we don't want it exactly one project per state and that's the maximum, which I know that's not what you're suggesting. It's just that we do want to encourage the efficient development of strong players that can actually follow through on their commitments and deliver this renewable power to the grid.

COMMISSIONER CLARK: Thanks. Laura?

MS. CHAPPELLE: Yeah, just real quickly. I guess I do want to defend the "one-mile rule", but within the context of existing facilities, especially -- and again, whatever prospects -- it does concern me, I guess, as a former Commissioner, I don't like hearing about gaming of the system and breaking down projects to such small, you know, megawatts because it's one of these -- if, to the extent that that's true -- it reflects badly on these smaller QFs that again, have operated very efficiently, low-cost, and otherwise within the system. So to that extent, I don't like hearing those examples, but hopefully whatever you do does lend some clarity and doesn't affect existing resources who have very real reasons for being a mile or less apart.

And then I just wanted to throw out, just my strong feeling of the importance of FERC, especially for

Michigan, which again is a state that after thirty-four years, is taking a hard look at PURPA. So it is a crucial time and, in my estimation, I'm hopeful that the utilities and the small QFs can reach some type of an agreement on what avoided costs look like going forward, in terms of service.

But to the extent, again, that we cannot -- the most valuable thing I can say today is FERC has a backstop, if you will, for a reason. And I've long heard that FERC doesn't like, you know, one-off complaints, but please keep an open mind. If there is some state decision that impacts a large majority of the small qualified facilities, we expect to be able to have that forum at FERC so you can take an impartial look at avoided costs in PURPA terms, rates and service.

COMMISSIONER CLARK: Thanks.

MS. SIMON: Any other follow up questions? Yes.

CHAIRMAN BAY: It's been a very helpful discussion on the "one-mile rule". So let me ask this question. For the panelists who've spoken in favor of PURPA, leaving aside the CHP issue and leaving aside the avoided costs rate issue, which will be discussed this afternoon, what would be the top ask of panelists who have been supportive of PURPA and the implementation of PURPA?

MS. CLEMENTS: I appreciate the question, Chairman. I think the place where rules don't exist that should, or hopefully will, exist is on the practice of utilities as relates to its specific contracting terms and posturing and interactions with potential qualifying facilities.

Those potentially, because PURPA is kind of coming of age and starting to bear fruit, we're now seeing utilities who were kind of okay with it for several decades, because there wasn't a lot happening, starting to make it a lot harder to interact with, and so you look at things like, in the Western states the contract length, the standard offer going down from twenty years to two years in Idaho, to challenges in Oregon, to fifteen years from twenty years in Utah, and a potential trend there that is troubling from, you know, a contract length that is not long enough to get financing before you're done. You can't implement PURPA's intent there.

Things like the sizes of projects for which standard offer contracts are offered. In North Carolina, there's a legislative bill consider decreasing that size between that potential and other states as well.

Fair interconnection processes, consistent interconnection processes, including for small, the very small qualifying facilities, going to the next panel, you know, the frequency of review of avoided costs from a certainty and consistency perspective.

All of these things are kind of a bucket of issues that are starting to crop up and we're seeing trends. And I think, if you're going to go and try and fix reforms on the other side, we are concerned that some of the developers might be gaming. There's this series of rules that FERC has within its authority to be able to at least offer some sort of minimum standards that would apply. Then states could adapt and adjust, based on their specific circumstances.

CHAIRMAN BAY: Okay, thank you, Allison. Todd?

MR. GLASS: Thank you for the question. I would completely agree with Allison, her comment. We need a minimum set of parameters for these types of contracts. We need a fixed price. If it's not fixed, it won't be -- we can't develop and finance it.

We need a financeable term. Two years is not a financeable term. It is not. It won't happen. It can't be financed if all you've got is a fixed price for two years. There is no generation that's being financed on a merchant basis. You know, QFs don't get financed that way.

You know, limited nondiscriminatory curtailment provisions, equitable security requirements, elimination of change of law risk or regulatory out provisions, there are regulatory out provisions that, for instance, say that if any time during the pendency of a ten or fifteen, twenty year PPA, if there is a disallowance by the State Commission, therefore, we're going to go in and change your PPA price.

That type of thing just kills the ability of project finance. And then finally, I would go back to nondiscriminatory straightforward interconnection practices. That's absolutely key and I think the Commission has done a fantastic job since Order 888 in rationalizing how people interconnect with the transmission grid and making it predictable and making it in a manner that can lead people to make rational economic decisions about whether to develop a project or not.

But it's a difficult dance around that where a QF trying to locate on a distributed, you know, distribution level thing, that's very difficult, and with all due respect, I think a lot of utilities in the country would simply prefer not to interconnect QFs on the distribution grid. They would just prefer not to. They would prefer to go through RPSs and buy the transmission grid and all of that. We're running into that and we see it manifested in how we're being treated in interconnection processes.

CHAIRMAN BAY: Thank you, Todd. Bob?

MR. KAHN: Yeah, just to endorse the specifics that Todd Glass walked you through. I would endorse that entirely and to key off Commissioner Clark's comments. Yeah, we need to be on the watch out for the gaming by the regulated utilities. The notion of cooperative federalism is going to work if it's a two-way street.

And then, at the risk of being just a little out of the box, we continue to appreciate FERC's gentle circumspect support of our creation of the Westwide ISO headquartered in Folsom. Because at the end of the day, that's kind of what we're looking for here. Access to a market. We suffer under the monopsony power situation.

And that's why all this stuff about PURPA. It's there as the backstop. But it is not the preferred outcome. What is the preferred outcome, is that ISO. So we know it's difficult, but we are making progress and that's why we care so much. Top to bottom.

CHAIRMAN BAY: Thank you, Bob. Jerry?

MR. BLOOM: Thank you, Chairman. In terms of the California Cogeneration Council and our experience, I think there would be three asks -- I certainly concur with a number of the comments. First and foremost is, we really think it's critical to maintain the mandatory purchase obligation and we do need to look at the interconnection and the ease of interconnection.

The second one -- a number of the panelists have referred to this -- there are contracting abuses that are occurring, megawatt size limits that are just completely unrealistic, terms of two years -- that whole trend that's going on in the states across -- someone needs to step in and say, "Wait a minute. That's not PURPA. PURPA didn't mean two years." These were long-term commitments.

And the third thing. I'm going to step out, a little bit out of the box, too, is we need to take and ask FERC to take a more careful look at these markets that are emerging. So with due respect, in terms of CHP and others, there is no capacity market that provides long-term capacity and energy pricing. Those markets don't exist.

So we have been caught in this paradigm, where we're looking at the existence of whether it's MISO or PJM or whatever it is, these markets are not providing the type of compensation that was contemplated and so the third ask on our side would be, as we look at, and particularly in California, we suspended the "must take for above 20 megawatts", but the message is, those markets are not working for us.

The markets that exist, the Cal ISO markets, the regional markets, are not providing a viable output or a viable option to put your power. And we really need FERC to start looking at that and saying, "Wait a minute. Maybe the criteria in our analysis here isn't what we thought it was." Because what we're seeing is a drop-off in CHP. You don't have new development, because there simply isn't with an absence of a mandatory purchase obligation, there simply isn't a viable market that provides the compensation that we need to continue operating or to build new generation.

CHAIRMAN BAY: Thank you. Anyone else? All right. Thanks everybody. Colleagues? Cheryl, Tony?

MS. SIMON: Thank you very much. So I wanted to actually go to this issue of the 20-megawatt rebuttable presumption in the organized markets. And some people have felt that it's very important to retain that limit, and other people have felt that it's important to remove that limit.

So I wanted to ask a number of questions, and people can take them up as they see fit. So my first question is, is there an alternative, for those who think that the 20 megawatts is the wrong number, is there another number that would be more appropriate? Is there a size limit? It just isn't 20 megawatts anymore, and is there some other number that might be more appropriate?

For those of you who think that the 20 megawatt should be retained, can you talk a little bit about some of the challenges that the smaller units actually do face getting access to those wholesale markets, and for those who think it should be eliminated, would there be a presumption that could be rebutted, that is, that a QF would have the opportunity to show that it did not have access to a nondiscriminatory market?

And what type of a showing would be expected to make so that they could have a purchase obligation? So my guess is everybody's got some thoughts on this topic, but we'll start with Laura.

MS. CHAPPELLE: Why am I the only one that has a card up? That's odd. Let me just say off the top of my head, again, that's an excellent question. But I think with regards to the size limit, I think the size is just right, that the rebuttable presumption should stay on the 20 megawatt in smaller facilities.

And I'm thinking in Michigan, you know, an 18-megawatt biomass plant is very similar to one of our 2-megawatt hydroelectric plants, in the sense that, these are not -- they're not market savvy. They're not like transmission owners or large generation owners that have a seat at the MISO table.

In fact, I was thinking off the top of my head, for all the years I've worked within MISO and PJM, they don't have a segment for, you know, small qualified facilities. They're not at the table. And again, that's beside all of the points on that market simply a year ahead market, in MISO, could never truly compensate, even in an IOU for their operations, right? So an IOU in MISO would not say, "We'll simply rely upon the MISO market full-scale for energy and capacity needs."

So mandating that an 18-megawatt biomass plant do so, for their costs, again, it's just patently discriminatory and unfair. But mostly I just wanted to say that the size seems right, again, for these real existing facilities that don't operate within the wholesale markets and the wholesale markets are not set up to be long-term resource adequacy, you know, functions for these facilities.

MS. SIMON: Allison?

MS. CLEMENTS: Thanks. To Laura's point, I think there's a new class of customers coming in, commercial and industrial customers, not all of whom are highly sophisticated. Some are, but that size is right about where they're coming into the market, 5 megawatts plus, and I think that's an important consideration.

When it comes to the specific challenges that potential qualifying facilities under 20 megawatts continue to face -- we've heard a few of them -- the interconnection at the distribution level that Todd mentioned, not only has interconnection issues, but there's potential pancake rate issues, distribution charges before you can get your power onto the wholesale system, transmission system.

There are also a bunch of costs that come along with the development of projects that don't scale. If you're having a party, and you're going to rent a band, it costs the same if you rent that band for ten people or a hundred people.

So when you're thinking about the engineering costs, and you're thinking about the legal costs involved, especially when you're not working with a standard offer contract that provides certain year-round curtailment and indemnities and all the provisions that Todd mentioned earlier.

Those have still specific challenges. When it comes to just the administration of being a small developer and staff to -- from a control room perspective to filling out the right forms, to even trying to find the right committee meeting in PJM or MISO, let alone, kind of being able to engage productively around the content.

All of those are specific challenges to smaller generating developers, even in markets with otherwise, kind of, rules on paper that provide access. And I think those are the reasons and FERC, as recently as last year, has put our position as kind of recognizing that rationale, which we continue to witness around the country.

MS. SIMON: Jerry?

MR. BLOOM: Thank you. In terms, Julie, your first question. I'm kind of caught as to saying I think I can cause comments, 20 megawatts is fine, but given our membership and when we have industrial manufacturers who produce a lot of steam, frankly, even the 20 megawatts isn't high enough if there's not a viable option or alternative, in terms of where you put your power.

In terms of the less than 20 megawatts, we've already mentioned interconnection, but I want to mention another one, which is the contracting. When we suspended the greater than 20 megawatts in California, we also negotiated a new standard offer for under 20 megawatts. If you get rid of the mandatory purchase obligation for under-20, the small QFs are not going to have the ability to sit with utilities.

We've known this since the early '80s when we needed standard offers to get this industry off the ground, but even today, fast forward thirty-five years later, we still needed a standard offer agreement. So another issue is certainly contracting.

And the third issue is the small QFs who don't have the ability, their widget manufacturers, their schools, their prisons. They don't have the ability to go in and play these markets. They don't have the ability, certainly in terms of CHP again, to move with the fluctuations in the market. This is a very different opportunity.

And the third one is the presumption, in terms of the QF's access to the market. I also want to again change the question a little bit. It's not access to the market. It's what the market is. Having access to a market that doesn't give you enough payment in terms of compensation to own and operate a CHP or renewable facility becomes meaningless.

So it's not just the existence of market, it's not just the access to market, but it's the specific focus which I made in my last comment, to what that market is and what the products are being sought in those markets and whether they meet the needs to now, the PURPA QF facility actually get built, operated and maintained.

And that's the key that we're missing is that you have to look at what those markets actually are. It's not just access, it's the market, it's the compensation, it's the products that those markets are seeking.

MS. SIMON: Charles.

MR. BAYLESS: Yeah, I don't really have a "brightline" solution which everyone likes. Though, if you look at the 20-megawatt demarcation, it's not really having much of an effect, at least in North Carolina. Every year the IOUs in North Carolina are required to file a report with the North Carolina Commission, stating interconnection requests in PPAs.

In 2015, there were 723 interconnection requests outstanding. Only twenty-five of those were over 20 megawatts. Most of those had not even been filed with the North Carolina Commission yet. Out of all the PPAs that were outstanding for Duke and Dominion, there were 887, only five were over 20 megawatts. So the 20-megawatt demarcation is having a very little effect on most of the PPAs.

Now there -- I'll admit, there are quite a few unsophisticated players out there. But there are also some major players out there in the under 20-megawatt category. I went back to that same report and, out of all the PPAs with Duke in progress and Dominion, 104 of those 887 were with one solar provider. And only one of them was over 20 megawatts. So there are some very major players out there playing in the under-20-megawatt field.

And in North Carolina, we have the additional problem -- 5 megawatts may not even be proper. The NCUC requires standard contracts under 5 megawatts. We have many, many projects to come in at 4.998 megawatts. There is a constant flow every day of those sort of projects.

MS. SIMON: Thank you. Joel?

MR. SCHMIDT: Thank you. Great question. As would be expected with EEI's diverse membership, we did have this question come up and being from Iowa, I guess I'll say this probably falls into somewhere between a straw poll and a caucus response, but I think it can give you a directional to the question.

I think generally most of the membership was probably maybe 0 to 5, maybe to 10, seemed like the sweet spot. We were of firm agreement that it needs to be looked at. I think that's come through on a lot of the comments. We obviously had some members that were at 0 -- just do not think it's there.

As far as the second part of your question about access to FERC to work through differences, I think it would be hypocritical on our part, and was not our position that it's a one-way street in here. I think it's a matter of we see that.

Hopefully some of the guidance and some of the other options that we've put forward would not overwhelm you with those types of one-off hearings, but I think if we can focus on that, because I think what's really coming through here is, what was very similar markets in 1978 are limited options, now has so many different facets to it that really have to be taken into account.

But I do want to go back. We kind of keep avoiding avoided cost and I do look forward to having the bleacher seats this afternoon, because I do think, what it's reminding me of is, every commercial transaction I've been involved in since I bought my first piece of candy as a youth to working on PPAs and EPCs and every other acronym in our industry, it still comes down to price and compensation.

There's been a lot of talk about what is needed for the financial viability of the developers. I can relate to that. I relate to that with my industrial customers, with my small customers as well. I believe my role, our role, as the service providers is to take into account the value they bring. It's not really my issue if that compensation makes it or not, and hopefully we can have better systems into the future to work through that.

When I think of small players in this, I think of my customers. Our service territory, 25% of our customers make less than, household incomes of $25,000 or less, and 50% make $50,000 or less. So cost, when other options are available, have to be considered. We always have had to, and I can't see this industry not having to look to the future.

We have to do some predictions, some commitments to future prices and we have to bring that into the system. So back to the direct question, somewhere between 0 to 20, landing in the lower quartile.

MS. SIMON: Thank you. We on the staff struggled also with the basis of deciding which issues were on this panel, and which were on the afternoon panel, but we couldn't do a whole day with twenty of you, so we had to break it somehow and this was -- we understand it's a little bit of a Venn diagram, but we appreciate everybody staying on this topic and look forward to this afternoon as well. Irene?

MS. KOWALCZYK: Yes, to us IECA members, I think that 20-megawatt threshold feels about right. But I would say, interesting we have experience, say, in Virginia, where we have the standard contracts for those under-20 megawatt QFs and we haven't seen that same just massive amount of inter -- requests that we had in North Carolina that was described.

I think that's partly because in North Carolina, it was compounded with kind of investment tax credits that were given at the state level and you had the production tax credits at the federal level and -- this just made it so incredibly fruitful to pursue those projects where we didn't have those issues in Virginia. And so I think it's not a PURPA problem. It's all of these compounded incentives that have resulted in a proliferation of huge number of these projects.

Getting to the other question that you asked, where are the challenges that we still face? I would say, and I know that you've wanted this for the discussion for this afternoon, but really, in the area of interconnection and the standby rates, I know that the FERC had put out rules that said that "the design for the rates for standby services should not be based on the assumption that forced outages by QFs will occur simultaneously or during the system peak or both."

And yet we've seen lots of situations where utilities simply refuse to design standby rates according to these principles. On the interconnection side, for CHPs in particular, as I noted in my introductory comments that CHP units should be not put into the over-20 or under-20 based on the entire size of the facility, but rather on what they could export to the grid. Because most of the output of the CHP units is used to serve load that's behind the meter for those industrial facilities.

MS. SIMON: Thank you. Todd?

MR. GLASS: I actually think that Order 688 and the Commission was quite prescient on 20 megawatts, and the solar industry, I would say, generally agrees. It's at sort of a natural break point for the development of a project and the financing of a project. Projects less than 20 megawatts are generally -- not always -- but generally interconnecting the distribution grid. The larger projects, larger than 20, generally transmission grid.

The interconnection processes are therefore different. The siting, the how the contracting, generally the larger projects can participate in an RPS, RFP or RFO, excuse me, Request for Proposal, the types of things that are run more easily. They have greater economies of scale, so they're able to compete. The smaller projects face a sort of a tougher set of just localized issues that we've been referring to.

And then finally it's sort of a natural breakpoint in the financing of a project. The smaller projects generally have to be thrown into a portfolio to be financed, because they're too small for any one financier to say, "Yeah, I'll put tax equity into that, or I'll put that onto this." They're generally rolled together, whereas projects 20 megawatts and larger, can be financed by themselves on a single basis. So I think 20 megawatts works pretty well.

MS. SIMON: Kendal?

MS. BOWMAN: Thank you. First, I'd like to address some of the comments -- when we were discussing North Carolina -- we serve a lot of customers in North Carolina and that's where I live. So I want to address, you know, first I think Charles was talking -- North Carolina's kind of hybrid. You have Dominion North Carolina Power that is a part of PJM, which is a very northeastern corner of North Carolina.

And then you have Duke Energy Carolina and Duke Energy Progress that serve the rest of North Carolina and are not part of PJM. So you've got kind of both worlds there. You've got access to PJM in the organized market, and then you have the bilateral market, or unorganized, what term you want to use for that.

But in North Carolina in 1984, the North Carolina Utilities Commission, I think it was really based upon small hydro, established that -- and you're allowed to under PURPA, you know, PURPA says 100KW and less is guaranteed standard contract, voided costs rights, and it's left to the states to implement if they want to do anything more than that. And in 1984, North Carolina established the 5 megawatts and less were guaranteed that standard contract and the standard voided cost rate, which was set every two years in North Carolina.

Fast forward to 2007 and North Carolina passes an RPS. They also have a tax incentive, a 35% state tax incentive on top of the federal 30% tax incentive, and then they also have property tax abatement, as well. You start to see a lot of solar adoption, particularly in the eastern part of the state, lot of farm land, lot of old tobacco farms that no longer exist, cheap land, open fields, no trees, perfect for large-scale solar development.

On top of that, you have this 5 megawatt guaranteed standard offer, avoided costs rates pretty darn good in North Carolina, historically, and you see this burgeoning bloom of solar development in the state. That's really -- it's a combination of factors. The 35% state tax credit incentive went away this December, December 15th. We've not really seen it let up yet on the gas pedal of solar development.

So you know, in my mind, it's not just the incentives, it's not the RPS, but it is driven by a combination of factors and one of those clearly is PURPA and the state's implementation of that 5-megawatt standard offer. And it goes into how you calculate that avoided cost. I agree that's for this afternoon's panel, but there are a lot of things you can do in the calculation of that, of what it costs, it can drive things one way or the other.

But back to your original question about, you know, what size? I think the question is geared toward the organized markets, at least in my comments. I was talking about reducing that size in the organized markets. Don't really have a specific number, but I will caution that whatever number, if you're going to change it, I think you see gaming and people playing around to that number, because over 60% of what's been developed in North Carolina has been at 4.99 megawatts.

And it's -- they're gaming that system because they can get that standard contract for 15-year term, so I caution you when you look at that, and I agree with Joel, I think it should definitely be at the lower end. I think developers definitely have gotten much more savvy. So I would say, looking towards the lower end would be better.

MS. SIMON: You provoked some response, so --

MR. KAHN: It's really a treat to hear Kendal express so vividly an IOU's perspective on what, from my points of view, it sounds like a really good thing. I mean, you know, you create incentives, that's a matter of state policy, certainly isn't a concern of FERC's. It's a matter of state policy to create a certain objective and the private sector steps up to do it.

Now I can understand concerns about gaming with the "one-mile rule". Actually I can understand that. But I don't understand how gaming applies to somebody who complies with your state ceiling of -- and comes in at 4.99 -- that just seems smart to me. That's not gaming.

So in any case, look. Somebody will see this kind of development as a bad thing and those of us here, in the middle of this panel, are thinking it's a good thing. And so, you know, and all the great use of tobacco land for solar development? That sounds really good to me. What is the problem? PURPA's clearly working in North Carolina.

MS. SIMON: We have some questions from the Commissioners

COMMISSIONER CLARK: Just a follow up this specific question, which is -- I'm curious if anyone has a take on whether the real issue is not so much the megawatt threshold level? Because wherever you set it, you're going to have that issue. Is the question more about the Commission's own precedent in interpretation with regard to the rebuttable presumption of the nature of access to the market?

In other words, has the Commission in those under-20 megawatt situations, has it hit the sweet spot where it's generally sort of gotten that rebuttable presumption right? Or is there something that we should be looking at differently in terms of how we analyze that particular issue, which I think will come up, regardless of where the line is drawn.

MS. SIMON: Comments on that? Or we still have people going back to the other issue? Jerry?

MR. BLOOM: I think I can hit the -- I had the same reaction, in terms of Kendal saying "gaming". If you set a limit, in California, the California Energy Commission took jurisdiction over permitting if you were over 50 megawatts, and we had a tremendous amount of 49.9 megawatt, because the permitting was done by the local agency.

That's not gaming the system, that's looking at the rules and participating based upon the rules you set. You can't suddenly turn that into "I'm gaming it" because I comply with the rule, or I structured my project to comply with the rule.

The second comment that Kendal made was of the attractiveness of what it cost. Again, that's this afternoon, but again, I go back to a point I made earlier. If it is the utilities' avoided cost, if it's not being set right, if it needs to be updated more, all those issues are there, but all the carrying on about the avoided cost is too high. It's not supposed to be. It's supposed to be the full avoided cost utility, but again, that's an implementation issue. It's not a problem with PURPA if it is avoided cost.

In terms of the rebuttable presumption, I do think you have it about right at 20 megawatts. Smaller QFs, they don't have that ability to access the market in the same way that larger people do. Again, what is the product? What's the market, what's going on? How are they reactive? Those types of things. So I think your, to answer you, Commissioner, are right at about the right size limit. Todd laid out a lot of the issues as to what types development, who are these developers are.

But small QFs don't have that ability to understand and play in the markets and access the market and is certainly the point I've been making a lot today and certainly the CHP, those marks don't provide a product or aren't buying the product they're trying to provide or sell anyway.

COMMISSIONER CLARK: Just quickly, to clarify my question. It's not so much about the, whether we've got the megawatt threshold right. It's more about once we -- regardless of where that's set, once we get a request to determine whether there's actually access to a market or not, do we have the standards that the Commission has been using to either, to sort of rebut that presumption? Has our analysis been generally right in that? Have we, or have we set up an impossible situation where it can almost never be proven that they have access to the market?

MR. BLOOM: That's exactly the issue that I was addressing in my latter comments. The answer, I think, is no. I think, in terms of what those markets actually are and how you access them, we're not getting it right and the proof of the pudding is that, when we're suspending the mandatory must-take, the cost of those markets. And then CHP, for example, stops developing, obviously that didn't provide the access.

So I think the answer to your question is, we're not getting the criteria right, we're not analyzing what those markets have correctly in making those determinations, and I think that's a critical issue if we're going to have the continuation, certainly of CHP, and in terms of grid modernization and the types of things, the distributive generation that we're looking at. We need to look at it differently to answer your question. I don't think we're doing it correctly.

MS. SIMON: Todd?

MR. GLASS: Couple of quick thoughts. The first one is, is that, the 20-megawatt rebuttable presumption works and I think, for the reasons I've said before, I think it works. I think that when you look to the ruler by which you can rebut the presumption, it starts with the statute, and the statute, I think, makes pretty darn clear how it -- and so I would remain true to that. I think that there is some confusion that we had in the West in the go-round about 20-megawatt projects versus 5, and what's going on in North Carolina, which I think is useful.

The reason why people are designing 4.999-megawatt solar projects in North Carolina is because once you go over 5, you're thrown into a very difficult contracting situation. It's -- they would much rather do 4.99999 and get a standard offer contract where you can fill in the blanks and get the avoided costs and be off to the races, versus something larger where you may never get a -- .

That's sort of some of the dynamics, because it is a really superior situation to be able to not have to negotiate the terms and conditions and some of the things that are going on in ecoplexes, you know, and some of the developers there are encountering having to go to arbitration to get to the point where they have a financeable PPA and then two weeks later, being presented with a different PPA, but strips out everything that just came out of the arbitration. Just two weeks before.

There's this -- the dynamic of abusive contracting practices, which one would almost think that their desire is to make the PPAs for those projects, you know, unfinanceable, as a means to get rid of projects in the queue.

MS. SIMON: Laura?

MS. CHAPPELLE: Just a few thoughts. One, Commissioner, I think the rebuttable presumption needs to stay with the utility. And that's important to say. Putting this presumption, however you fashion any changes, somehow on the QF, is -- and various commenters have detailed this particular topic -- but would be a particular burden to kind of, you know, approve a negative.

But the rebuttable presumption, preferably stays on the utility. In Michigan, it seems again to have been working under the current statutory guidance. And our two large IOUs received waivers for QFs 20 megawatts and above, over 20 megawatts, I should say, but something like in 2012 and 2013, respectively.

And I don't think there was too much pushback on that. Actually I think some of the pushback in one of the dockets was seeking FERC assurances that the utility was actually asking for the waiver for over 20 megawatts, not under, because that is so sensitive, even back in 2012, 2013.

So you know, but the framing is right, and I can't go beyond answering this without getting into avoided cost, but I would encourage you -- I think the comments on the question of what is nondiscriminatory access mean, and in Michigan, one of our utilities offered to be the middleman -- "We'll help be the conduit into the MISO market."

But again, when you're looking at avoided costs or you're looking at how this is set up, it should be reflective of the utilities' avoided cost. What the utility is essentially obtaining itself for energy and capacity. And when the utility is obtaining a rate far above the rate that they're trying to impose through market access to a QF, somewhere upwards of 50% lower, it's nondiscriminatory access.

And so that has to be taken into account, drilling down to actually, what does that mean? What would it mean to a small QF in Michigan? To subject them to the MISO market, cost-wise? And if you look at that, you'll probably find it would violate, you know, PURPA's requirements of being nondiscriminatory access to the QF.

MS. SIMON: Joel.

MR. SCHMIDT: Thank you, Commissioner Clark and yes. For EEI, it is much more, I think, about the rebuttable presumption. I think Laura has stated where our position is, and it is different. It is our position that QFs in organized markets under 20 megawatts or fill-in-the-blank, prove that they don't have access to markets.

And it's really, again, back about this access to markets and clarity there. The industry markets have come a long way and I would say the rate of change and speed is only accelerating, so I think it needs to be taken into account that there's a level of burden of proof on both sides here and that's where I think the clarity and guidance can be very helpful.

MS. SIMON: Allison?

MS. CLEMENTS: Commissioner Clark, I appreciate that question, and I think that the cases that I have been able to find where the Commission has made a determination on the rebuttable presumption, saying that the smaller than 20 megawatt QFs do, in fact, have access to the markets in Fitchburg and Burlington. It was a very facts-specific analysis. And that's what the beauty of rebuttable presumption is, is that the facts matter.

I think in this case, just like in 2005 perhaps Congress was really forward-looking when it was thinking about, you know, real opportunity for long-term capacity sales for small QFs in a large part of the country. We're not there yet on this below-20 megawatt piece. And so the ability for utilities to come in and say, "Hey, this isn't right. These guys are playing all over the markets. They're selling capacity energy ancillary services." That's great.

But if you think, just for example, in PJM, where there've been a lot of rule changes around the capacity market, you think about a small solar developer who's got some 10-megawatt projects, even five 10-megawatt projects. To master the understanding of how resources can participate, how they can aggregate, which parts of year, what products they qualify for -- that is coming. We're not there yet.

And so, in that case, I think the status of this rebuttal presumption kind of provides everybody with a fair opportunity. And to the point that Laura made, I do really think, and we've -- this is kind of a theme -- that the small qualifying facilities don't have their resources, legal, financial, otherwise, to start bringing up all these issues on a one-up basis at first.

So to the extent there's an opportunity within

FERC's jurisdiction, to provide some sort of expedited access or kind of low, you know, easy, like the small interconnection procedures on the PURPA front, I think that would be helpful on this front.

MS. SIMON: Okay, I don't want to take up all the time, so I'm going to turn to my colleagues. Larry, did you have any questions?

MR. GREENFIELD: Actually, there were several that were prompted by the conversation this morning. Let me start off with a general question. There are a number of people on the panel who noticed, or commented that, in order to really promote or develop QFs, the developers need longer-term contracts. They need more than a year or two.

And I was wondering, because I don't think the utilities are the cooperative representatives on the panel, for that matter, Mr. Kjellander, really had a chance to respond to that comment, because we wander off on other directions on other topics, and I thought it's worth perhaps taking a moment or two to talk about what kind of contract length the QFs need or don't need, as the case may be, in order to develop -- I'll pose an open-ended question and I'll let President KJellander take first crack at it.

MR. KJELLANDER: Thank you. I think, simply put, my role is to be an economic regulator and so, as I began to look at some of these cases that have come forward, one of the clear functions or -- it really isn't a function, it's not my job as a regulator to make a developer rich. It is not my function as an economic regulator to ensure that they can get a project financed.

Instead, you know, it's to look at the overall balance of whether the resources need it, whether the price you can get for it is correct, where they can get it in the system. And ultimately, what the financial impact is on the customers.

And what we've seen, and I mentioned it earlier, is that, with PURPA today, in order to deal with the disaggregation problem that we had, the tools that are in PURPA are very blunt instruments, in a way to try to get at trying to avoid this, this gold rush effort to get these projects online in large quantities.

So we were left with having to tinker with the spigots that we had that are very blunt. And so the gaming issue, I think, really, is what led to a lot of the adjustments and changes we've made at the state level in Idaho over the last six to seven years.

If that disaggregation issue were resolved or had never emerged or had the ability to deal with it in its time and place, we might not made some of the decisions that we did make at the state level over the last five to seven years because we could've addressed the issue of disaggregation and not seen that flood of projects come in in a lumpy scenario in which they emerged, and, at an extraordinary cost to customers at the end of the day.

So I guess, just in general, that's where I wanted to be with that response and I realized that, you know, stating it the way I did, maybe some people think that I'm not a capitalist. Now, capitalism's great. It's fantastic, but when there's a potential impact on customers that is bringing on resources before we need them, meaning we have to pay for resources before we need them, as an economic regulator, I have a problem with that.

MR. GREENFIELD: Bob, you are first up.

MR. KAHN: I want to call attention to a semantic issue that's important. In Idaho, there's no such thing as an electric customer. A customer is someone who can shop at Macy's, Target, Nordstrom's, Neiman Marcus, whatever they can do. That's a customer. What there is, in Idaho, Oregon and Washington, are captive customers or more commonly known as rate-payers.

So in President Kjallender's role as an economic regulator, you got to start by getting the semantics right. The Idaho Commission is more than capable of performing its job, and it does. When it comes to PURPA, it has overreached. The two-year limit on contracting, which kills development flat out, for reasons I'm sure others are better qualified to explain, was precedented by decision on the LEO, legally enforced obligation, where the Commission overreached, shall we say.

So, in any case, let's get at least the terminology right. At the end of the day, the proof is in the pudding. Historically, PURPA projects have outperformed, meaning given rate-payers' lower costs of power than Idaho power has. And, you know, we don't have to quibble about facts or an agreement there, but the record will show it at any time if anybody wants to see it.

MR. GREENFIELD: Todd.

MR. GLASS: Thank you. Great question. How long of a term is long enough? I think you start with the statute. The statute says "encourage cogeneration and small power production." That doesn't mean encourage it, but then don't let it actually be built.

Second thing, is you look at Order 69. Order 69 made very clear that it was a long-term contract to provide energy and capacity to the utility, not a short-term. Two years is not long-term. I don't think I've ever heard of two years as being considered to meet that requirement of long-term. The reality that I pointed to on my opening statement is that fifteen to twenty years is long-term.

The Oregon Commission, in discussing it, made it fifteen years fixed price, and then prevailing market price for the latter. That's still long-term, and that is still financeable at fifteen plus market price. Two years is not a long-term contract. It is not financeable.

You know, this is something that I think that the Commission really should look at, and look at very deeply, and look at what's happening throughout the states. I mean just last Friday, the North Carolina Commission said, and I'll quote, we will "for 2- to 20-megawatt projects, we will decline to require that they entered into a PPA of a stated length, and we will leave it to negotiation."

Who's got the market power? Who's in charge? The Commission, this Commission, in its enforcement role, should be in charge of making sure that Order 69 and PURPA is observed. A long-term contract means a long enough time to be able to develop and finance a project.

MR. BAYLESS: I'll start off by saying, we don't have customers either. We have members who actually own the distribution co-op and the electric distribution facilities. But there's been talk about the inability of small QFs to obtain contracts because of their size and they need a longer term. But there's another side to that. Not all of us are IOUs with a million customers and billions of dollars of assets.

Our smallest member in North Carolina is 8,000 customers during the peak tourist season and 5,000 members on off season, so it's in the outer banks of North Carolina. Entering into a fifteen- to twenty-year contract for that Co-op would tie up a significant amount of their assets.

Something around the five-year range would probably be acceptable to them, but if they were forced to enter into some of these very long-term contracts it would represent a significant amount of their generation, significant amount of their power supply contract for a long time and they have less headroom to absorb those types of contracts, as opposed to larger utilities, so just something to keep in mind.

MR. BLOOM: I think Todd hit -- well, the one or two years for a number of reasons that have already been stated -- it's not long enough to develop a contract, in terms of anything that's really viable. For example, again, in California and in our settlement, existing QFs got five-year contracts, new QFs got twelve-year contracts, so they could actually realistically have some possibility of developing new contracts.

The other issue I just want to respond to again. We keep hearing these comments that we're not here to make developers rich and the impacts on customers. I'm not sure what happened to the avoided costs and the rate-payer indifference. Avoided cost is the cost to procure or produce the power by the utility.

So again, coming back to the basic problem here, if it's not being done correctly, the problem isn't PURPA and avoided costs, it's the way it's being implemented. And those fights have gone on for, certainly in California, since 1981, '82, and continue, you know, all the time.

The Commissions have the ability to get avoided costs right, but complaining that somehow avoided cost, if it really is the utilities cost and the rate-payer's indifferent, it just -- I can't quite get my arms around why we have this huge problem that keeps getting complained about, because that's really not the issue. It's not PURPA. It's the implementation.

I know you're going to deal with that this afternoon, but I think it's offensive, frankly, to keep saying that we're not here to make developers rich. We're only asking for avoided cost, as was to be determined and there are rules and regulations and plenty of guidance is that making those determinations.

MS. SIMON: Larry, anything else? Bob? Stan?

MR. WOLF: One question I have -- I guess starting off with utilities, but I'm sure the other folks have views on this. We've heard a couple times some notions of, we may not need the additional supply. There's a tipping point or so forth. What perspective is most helpful or what can help in analyzing this?

I mean, are we talking about when you start dipping into -- start pushing away base-load supply -- does that create a problem? Where do the big costs cut in, and can you give us some more description of that? When is it a problem for the utilities -- when does the rubber meet the road in terms of big difficulties arising in taking additional renewable supply under PURPA or any other supply?

MS. BOWMAN: I'll start and I'll just say, you know, every balancing authority area is different, and every balancing authority area will likely have a different, for lack of a better term, what you described as a "tipping point" or how much they can absorb, but, you know, what we've noticed, particularly in the Carolinas, is it is not so much just this, you know, megawatt threshold amount, but it is actually where they're connecting. What speed? Or you have to go down to the specific feeder level to really analyze the impacts?

And a lot of that is done in the interconnection process, but we have started to notice, and I believe I had some charts in my comments, that in certain times of the year, and certainly in the summer and I'm really here talking about solar, because that's what we seen the proliferation of in North Carolina.

You know, it's certainly -- they're a benefit to the system in certain times of the year and other times of the year they do cause a problem with the system and right now we're managing it and, you know, there's no fear that the lights are going to go out in any way, shape or form. But there are just certain times of the year, particularly in the fall and the summer and to some extent, in the winter, that you will have to start shutting down some of your base-load facilities, or in the alternative, dumping energy, for lack of a better term.

We are certainly not there yet. I don't want to say the sky is falling. But if you continue to see the amount going in the future, without any more planned needs-based approach, you could get to a point where you're going to have to spend a tremendous amount of money in upgrading the grid to accommodate it, or do something drastically different than what we're currently doing today. So, I don't know if that answers your question.

MR. SCHMIDT: Thank you and as Kendal mentioned, it really comes down to time and place. So it's going to be different if it's base-load or not. I think most of us in the industry are facing lower load growth than we've been used to, and that's from a number of factors. Obviously, natural gas prices, as we know, are changing dispatch, you know, by the minute, by the hour, by the week.

As well as T&D congestion is starting to play much more into this, so all generation, regardless of that you're measuring it in -- you know, KW's at the smallest level to be it utility-owned, be it merchant, be it unorganized, be it in bilateral, is under economic challenges.

In our particular area in the mid-West, five, ten years ago, the question was much more "if renewables" and now the question, both for short-term decisions, which is "in less than minute" timeframes at our dispatch centers and what we have to manage load, and also, as I'm considering long-term investments, be it in modernizing the grid, being it in maybe life-extension for other assets, or these new assets, it also comes down to, not "if renewables" for most of the energy portion, we haven't got the capacity and all the other things figured out.

I think it will come with time. But which of those -- and air organics continues to us to come back to the customer. And what are the customer choices? And what is really fair for those customers if we call them rate-payer, whatever, and I can get to that, but every phone call I've got from a rate-payer was a human voice that is a customer of our product through my career.

So I think it really gets to back to, "it depends", which I know makes FERC, state regulators, everybody around this table, I'm sure everybody in the audience, job harder. That's the privilege we have of being in this industry and really making meaningful change for the health, safety and welfare of our country and our citizens.

So I think, unfortunately, there's not going to be a silver bullet, one-size-fits-all answer here, but I think you really have to look at it in, I think it's a matter of "who should be controlling that" and "how should those decisions be made and what is -- what are the systems to make sure that the parties have fair treatment and that it's brought forward. And I do believe FERC has a significant role in that, as I stated earlier, in providing guidance.

MS. SIMON: Jerry?

MR. BLOOM: So when I hear utilities and owners talk about me, a chill goes up my spine, because the reality is that the utilities have the ability to build, to procure, to go under contracts, so what we see in a lot of markets is, no argument that the plate is now full. We were approved by the Commission to build these projects. Going to your comment, Joel, base-load projects. We don't need you anymore.

And the question is, to me, that we have to look at, is what's the resource planning? What are the assumptions that go into, so that we don't get into an argument, that there's no need, simply because they went out and procured a whole lot of stuff, so there's no need for these QFs anymore because our plate is full.

So there's a basic underlying long-term procurement, modeling assumption, so forth, as to assuring there's a place at the table for the products and -- I'm going to go to your last point, Joel -- there's an evolution going on around the country and a revolution, which is the consumer who's demanding and wants green energy and green power and renewable power and efficiently produce CHP power. And that is what consumers are looking for. And we have to figure out how to meet their needs and what they want when we design this.

The second thing is, we keep hearing about the overgeneration. But I want to go back to -- a few of us have made comments on this -- within the context of contracting, and if the pricing is done correctly, there are ways that you can have, and this is happening across the nation now, curtailments in dispatchability -- all those things are possible if we look at the way we manage and operate the resources we're bringing in.

So the answer isn't, "Let's get rid of, or suppress the resources." The question is, "How do we effectively the resources?" And that can be done through contracting, other mechanisms. It's not simply yes or no, or it shouldn't go on the -- or we should block them from getting onto the system. It's how we use them and integrate them into the system.

MS. SIMON: Laura?

MS. CHAPPELLE: Just real quickly. Again, in terms of capacity needs, and I know this is a utility question, "How much is too much?" But my broad concern is articulated by Jerry, that we're witnessing in Michigan. You know, at a time, obviously when we're retiring a great deal of coal generation plants, and theoretically there is a need to replace some of that capacity.

At the same time that utilities are arguing in our Michigan legislature that they need to build new capacity, therein, PURPA State Commission Technical Conference telling the QFs that they don't need capacity. And I do not exaggerate that point.

So that's something real. Again, I'm here today to mostly talk about existing facilities, facilities that have been on our utility systems for years, decades, you know, there shouldn't be a displaced need for that reliable low cost renewable resource, simply because the utility decides to build a new natural gas generation plant.

So I just ask you to be very sensitive about that when you're figuring out, you know, where this drawing line should be of, you know, too much. Again, I understand there's unique issues going on in the West.

But at least, from Michigan's standpoint, there hasn't been this explosive growth, and what we see is, you know we're on your system. We've been on your system for years. We're low-cost, so you should factor that in before you go and say you need to build another few natural gas plants.

MS. SIMON: Todd.

MR. GLASS: Another great question. First, I would observe you start with the statute. Statute was not designed to specifically factor in the utilities' needs. I would be willing to submit that it's a very small number of utilities in this country that, since PURPA's been passed, said, we need QF power, and we want to do more QF deals.

I think it's quite the opposite. They haven't wanted it from the very beginning and they don't want it now. The second thing that I would say is, as you look at the specific issue, make sure to not do anything that is static, or that creates anything that's too cast-in-stone in time.

There are a lot of tools in the toolbox, both on the utility side, in managing the wires and the grid and the reliability, as well as on the developer side and the power producers' side. The utility has a lot of tools. And the market has a lot of tools.

And I think if you look at, for instance, what's been happening since we, in California, have been worrying about the CAISO's duck curve, you're seeing improvements. You're seeing everything from market improvements to the way that utilities are planning for, for the way that developers are responding to the need. So you don't want to lock things down.

Finally, I would say that, with regard to the, you know, the interconnection practices, which specifically go to this need -- it's not just a generation, but it's also a wires-specific question, you know, if we look at North Carolina, there's 350-plus QFs in the queue right now, waiting to get interconnection.

The fee was raised from $1,000 for an application for an interconnection agreement to $20,000-plus per megawatt load. The developers, by-and-large, went along fine, you know, with the fact that they had to pay more to get through there. Even though it was retroactively imposed.

Now there's -- the utilities collected something in the neighborhood of six million dollars in order to do this. Let's get on with it. Let's study, let's have an open process, you know, there -- just in the last week, there have been various assertions that there are power quality issues and that there have been bad projects installed, bad QF projects installed, you know, let's get down to the reality of the situation, rather than just using it as a reason not to interconnect.

You know, let's talk about what inverters can do. Let's talk about how we can solve the problems. Let's talk about energy storage, let's talk about things of that nature and resolve them, rather than just say "No. We need to be relieved of our PURPA obligations."

MS. SIMON: Bob?

MR. KAHN: Yeah, quickly, it is a good question. And to which I would respond, "too much for who?" You know, whom, who is affected? Well, clearly shareholders are affected. Utility shareholders are affected. It's too much competitive power coming onboard for their purposes.

And let's not confuse net metering with PURPA, because you know, when we talk about the West, the problem in the West, you know, it may well be in California and it may well be the duck curve, right? Which is a function of solar installations -- a spectacular problem to have.

Let's face it. No wonder, you know, PacifiCorp is so interested in expanding the ISO -- it's a great sync for free power. I mean, we can solve these problems. And the core function, it seems to me, of a utility is to manage the system from a T&D standpoint.

At the end of the day, that's their core function. They're more than capable of doing it. And at the end of the day, let's not confuse fundamental economic questions with solvable engineering problems.

MS. SIMON: Bob?

MR. MACHUGA: There's been a lot of discussion about contracting issues for new QFs. Have similar contracting issues been encountered for power purchase agreements that are expiring with existing QFs?

MS. SIMON: Laura is here on behalf of existing QFs, so we'll start with --

MS. CHAPPELLE: Yes, of course, but I'll start by saying I'm certainly biased. But I definitely commend our Michigan Commission for opening up a proceeding and spending some time after thirty-four years to really look at avoided cost issues and other contracting issues.

We did have to bring a complaint on behalf of these small QFs, in order to kick start that process, because again, it looked like it started to be utility-driven and at least one of the major IOUs was proposing short-term contracts at the MISO energy and capacity level, which would be somewhere around 3 -- 4 cents on a short-term basis, it was even proposed to do a year-to-year contract.

So yes, we had to bring a complaint -- it's very much before the Michigan Commission. It's taken some time, but I think it's been good time, valuable time, good stakeholder participation, but yes, we're very worried about contracts. We do talk about contracts for financeability, and I think maybe the assumption is, this is just for new large QF projects.

The existing projects, they also need to go to banks and work with their financiers and running these significant facilities for them and their local communities on a year-to-year or two-year contract is very questionable, so it affects their financing. But yes, we're living in Michigan as we speak, all of the issues that we're talking about here, we're working on in Michigan.

MS. SIMON: I don't know who was next.

MR. BLOOM: Thank you for that question. The California Cogeneration Council is all existing gas-fired cogeneration and it's been operating -- most of our members, in fact, all of our members signed their initial long-term power agreements in the early '80s to mid-'80s and came off of those contracts.

The entire problem in California was that the utilities, even before we suspended the mandatory purchase obligation, were refusing to enter into new contracts and we had our members, all of our members, basically with stranded investment and these are, again, operations that are integrated into manufacturing, schools, hospitals, universities.

We had a real crisis because utilities would not enter and I've been corrected. I think I said five and twelve years. The contracts that we negotiated, in terms of a CHP settlement, we had, there's seven years for existing and twelve for new.

But the problem with existing facilities getting under new contracts is a real problem and frankly, even with, as in my opening statement that I submitted in written form, even with the CHP program, where there have been extraordinary problems in terms of a number of non-CHP projects that qualified under the terms of settlement that led to the program, but converted to EWGs because they couldn't get CHP related contracts.

People who have shut down, people who have changed their operations, people are looking at change the operations if the 20 megawatts mandatory put is retained, but this is a very real and existing problem for our members in particular, who came off of contracts, couldn't get into new contracts and continued to need relief.

I will say that, even under the CHP program, these contracts that are seven years are going to expire soon, as is the problem in 2020, the program itself expires. We do need to figure out how -- I'll give you a quick example, but U.S. Borax operates one of the three boron pits in the world. They can't move, they can't go anywhere. They have extraordinary thermal needs. They had supported a

100 megawatts of generation there. They're going to come off of contracts. They need a place to keep operating.

And there's numerous examples all over the state and -- recovery and other businesses that are dependent upon contracts, so even the -- if say, the Band-Aid that's in place right now, as their seven-year contracts expire under the program, we have a real issue coming up as to what's going to happen with the continued operation.

The existing fleet, when we sign the settlement, provided 1.67 million metric tons of carbon reductions. Because of that that dual efficiency and much of that is being lost and the potential of what we wanted to achieve in the state is not being materialized because of the lack of the mandatory put obligation going for it.

MS. SIMON: Todd? Okay. Bob?

MR. KAHN: I'll be really quick. You know, one can't go into a lot of details. It's really not appropriate, but in one of the three states where NIPPC is active, in the last five years, two operating established cogeneration units faced expiring PPAs. Both were acquired by the IOU to which they were interconnected.

MS. SIMON: Okay. Do any of my colleagues have burning questions? Yes? I'm sorry? You still want to --

MR. GLASS: Just really quick. I'm going to pay the utilities a compliment. They do not tend to discriminate in favor of existing QFs. Existing QFs face the same difficulty everybody else does.

MS. SIMON: Okay. Adam?

MR. ALVAREZ: We talked about unneeded generation and a lot of the utilities -- they were saying that they don't need generation or they definitely -- building generation, and then another thing is, this is mainly for the utilities. What do you guys see as a reasonable resolution on moving forward with QFs?

MS. SIMON: So on that simple question, we'll hear from Kendal.

MS. BOWMAN: So, first, let me clarify. I no way, shape or form said we did not need any energy or capacity on our systems. Clearly there's always going to be some kind of a need. You're going to retire something, even with low load-growth. I'm just saying we need to roll into QFs in the process of our planning. In the needs-based approach, and do it in a, you know, in a methodological way, system planning, to operate your system as reliably and safety and optimally as you can.

So that's what I'm saying. I don't want to leave the impression that we don't need it and we don't want it. But we do. We just need to do it in a more systematic way. That's kind of my approach. I think in the comments, you know, our suggestions are to kind of go back to the founding principles of PURPA, do it on a needs-based approach -- if the utility, and I think I talked about possibly some kind of an RFP, where people come in and bid into the markets. I know there will have to be lots of discussion, that's probably something done at more of a state level than at the FERC. But clearly going back to the foundation principles of PURPA.

MS. SIMON: Joel?

MR. SCHMIDT: Kendal pretty much summarized for us. We do have needs for energy and capacity, but it varies where and when and I think we want to make sure there. We have a desire, and I think it can be demonstrated through interruptible programs, energy efficiency.

Some of this, that if we can get energy and capacity from our customers at competitive prices to other options, and other options now we can actually even say other renewable or green options. We're very much for working through that and having that, but again, it gets back to where and when and I think we've got to continue to evolve this marketplace as we have the wholesale and others to have more of those signals coming appropriately within that statute.

Now, to the thing about shareholders. Yeah, I agree, there's a difference between us owning generation that is rate-based in most of our models. I mean I think all of us know the formula. But a lot of our energy is purchased. We're a heavy purchaser of energy, so what I look at is like-kind, what's the best interest for my customers at this point in time, and have to make those decisions.

So if we implied that we don't want the energy and capacity, we always will have a need for energy and capacity in various arenas. We just have to make sure we do it in the best fashion possible.

MS. SIMON: Bob? And then Todd?

MR. KAHN: Yeah, I'll be brief, because we don't want to stand between ourselves and lunch for everybody, but you know, again, examples are helpful. So we have a leading utility, investment on utility in one of our states that proposed retirement of one of the coal-fired generation units, which is a principle source of power. And hinged their legislative proposal with full expedited replacement preapproval of them securing replacement for the retirement of that lost capacity. That's it. That's all she wrote.

In terms of going out to compete, in terms of, you know, maybe opening that incremental capacity that, you know, they claim needed to be replaced by them, maybe the market could've done that. So this is what we live with. And it's an ongoing reality.

Need should be defined in the resource planning and should be a function of fair competition to figure out what can be replaced most efficiently. Clearly, PURPA has a role in that. And we often find the utilities arguing against each other -- against arguments that they've made previously in other dockets. It's revealing.

MR. GLASS: I need to slightly divert the question of need to what the QF community needs. We need the Commission involved. We need guidance on how to -- the situation is a mess right now and it's getting worse with the divergence of fifty states doing fifty different things and all of the utilities.

We need your involvement. We need your guidance. We need you to be a forum to sort this out and to follow through with the statutory authority that you have.

MS. SIMON: Any closing comments from Commissioners?

COMMISSIONER LAFLEUR: No. Thank you very much.

COMMISSIONER CLARK: Okay, so this -- I'm hoping this is a really quick question. I'm going to get back to Todd's admonition, to always go back to the statute. I'm going to make a shocking admission that I don't sit up at night memorizing PURPA.

So, on this question of "how much is too much" and do we just reach a point where, for whatever reason, where it's interconnecting with the grid and the intermittency and the nature of it, there's some sort of problem that occurs. Doesn't the text of the statute itself allow for some off-ramps to take into consideration some of those things by an appropriate agency and if it does, is there a reason that it's not being utilized? Or -- I'm just curious if there is some sort of ability to get to that issue in the statute if we end up with those issues, either the state or federal level?

MR. GLASS: No, it doesn't. The two things that are in the statute are the rebuttable presumption and the doing away, which was added in EPACT 2005, and the avoided cost calculation, which is this afternoon's conversation, but that's where it's supposed to be addressed.

MS. SIMON: One of our goals was to have a very diverse panel, both in terms of industry representation, technology representation and geographic representation. I really want to thank all of our panelists for providing that today. I think we heard a good discussion of a broad breadth of issues, so thank you very much for being here. And we will convene again at 1:00. Thank you.

(Whereupon the Conference recessed for lunch to reconvene at 1:00 p.m., this same day)

A F T E R N O O N S E S S I O N

MR. GREENFIELD: I think we're ready to get the Conference back under way again. Welcome back from lunch. I think we're ready to dive into the issue of avoided cost.

We touched upon, not surprisingly this morning --a very lively suggestion, or I should say, a very lively panel this morning and being advised to speak into the mike reminds me that what we heard back from our television viewing audience was that it's important that everybody speak into the mike, and particularly when you're speaking to one of the Commissioners in response to their questions, do try to speak into the microphone so the television viewing audience can hear what you're saying, because otherwise they'll drop off and our Nielsen ratings will not be as high, and the government won't be getting the advertising revenues they would like from this television show. So with that in mind, let us get underway, and let's start with Mr. Brogan on my right.

MR. BROGAN: Good afternoon, Chairman, Commissioners and staff. I'm Al Brogan, Corporate Counsel for Northwestern Energy. I'm participating today on behalf of the Edison Electric Institute.

I'd like to thank the Commission for providing a forum to discuss issues associated with PURPA, as well as possible changes to the Commission's rules implementing it.

In response to FERC's notice, EEI proposed specific changes to existing rules that show up in redlines to those rules in our pre-filed comments. My written statement proposes some changes to 18 CFR, Section 292.304 and explains why these changes are needed.

Stepping back a little bit, PURPA rests on two pillars, nondiscrimination towards qualifying facilities, or QFs, and consumer indifference. PURPA limits the amount that an electric utility pays the QF to no more than its avoided cost.

FERC's rules require an electric utility pay QF no less than its avoided cost. This all sounds simple, but the devil is in the details. As reflected in the panelist written comments, and I think as reflected in some of the discussion this morning, determining an appropriate avoided cost rate is become increasingly controversial since the inception of PURPA.

In its rules, particularly 292.304(e), FERC identified factors that should be considered in determining avoided cost. However, the various methods that the states routinely use to determine avoided cost fail to reflect these factors and the dynamic market conditions.

Often, this failure forces utilities to enter into long-term contracts at fixed prices that are substantially above market. Our customers pay the price for these failures. We believe that the additional language in FERC's rules and additional guidance from FERC will promote consumer indifference.

By way of illustration, I'd like to specifically discuss one of the proposed changes. That is, of particular importance to Northwestern Energy. We propose to add a new section to 304(e) to clearly permit states to consider the cost of transmission system upgrades or the cost of network integration transmission services in the rate paid in the QF contract.

FERC's declaratory orders, particularly its pioneer wind order, appeared to specifically authorize consideration of these factors; however, QFs assert the consideration of them is not permitted or appropriate. Recently in dockets before the South Dakota Public Utility Commission and the Montana Public Service Commission, Northwestern Energy has advocated that avoided cost rates should be reduced by any other cost that the public utility incurs which, but for the purchase from the qualifying facility, the public utility would not incur.

QFs and other special interest groups have asserted that such a reduction is inappropriate, violates PURPA, is discriminatory and violates provisions of Northwestern's open access transmission tariffs.

When these additional costs that are imposed by a QF are not considered, Northwestern's customers pay costs that they would not pay otherwise. You, through your rules and your guidance, can provide clarity to the State Commissions on how to consider those things. Again, thank you for the opportunity to participate and based on the lively discussion this morning, I look forward to an equally lively one this afternoon.

MR. GREENFIELD: Mr. Burleson?

MR. BURLESON: Thank you. Good afternoon. I'm Jeff Burleson, Vice-President of System Planning at Southern Company. I've got responsibility for leading the support of our retail operating companies, generation planning, transmission planning and generation procurement. And I want to thank FERC and the Commissioners and staff, as well, for the opportunity to speak on this panel regarding the important issue of avoided cost calculations under PURPA.

Southern Company owns four vertically integrated electric utilities operating in the states of Alabama, Georgia, Florida and Mississippi. And it also owns a competitive wholesale generation business. Our retail companies serve about four and a half million customers and have a 120,000 square mile service territory in those four states.

Our business processes within the company put the focus on the customer in making sure that we're doing the things that are in the best interest of our customers. And what that really boils down to is ensuring that we're providing a reliable and affordable supply of energy for those customers.

Our IRP processes within our states essentially rely on a combination of owned generation, as well as competitively procured bilateral wholesale contracts. We require firm physical transmission delivery service for generation capacity that's serving our native load. We require either firm fuel transportation or some sort of onsite fuel storage, again, to support the reliable delivery of energy at affordable prices for our customers.

In some cases, QFs enter into capacity contracts with the company as well, and when they do, we incorporate that into our IRP planning processes. We also incorporate that into our system operations. In terms of the four states in which we operate, the avoided cost calculation processes are well-established and they are indeed consistent with PURPA.

We've got a wide array of options available for qualifying facilities to choose from, that include, from an energy cost standpoint all the way from hourly energy to annual energy projections, as well as long-term multi-year energy projections.

However, QF contracts that are based on any sort of long-term projections of avoided energy cost, do place economic risks on customers in the event that those long-term avoided cost projections turn out to be higher than actual avoided costs that are incurred. And therefore, Southern Company recommends eliminating the QF's option to select an avoided energy cost payment that is based on those long-term multi-year projections of avoided energy costs.

We don't give independent power producers who are selling to us capacity under long-term bilateral dispatchable contracts, the ability to lock-in an energy price. In fact, those independent power producers are dispatchable until we can turn them on and off with the energy price that they have bid in to an RFP, whereas with the QF, the energy price is fixed and we must take it in all hours, regardless of whether it's economic for our customers.

So, really, QFs should be situated no better nor any worse than any of the independent power contracts that we enter into. In conclusion, I just say that our state processes are working within Southern, but elimination of this provision that requires locking in long-term projections of avoided cost, would in fact, provide significant improvements to those processes, and I would encourage the Commission and the staff to continue to have dialogue with utilities and State Commissions, just to ensure that if any changes are made, that it doesn't result in any sort of unintended consequences. Thank you for the opportunity to participate.

MR. GREENFIELD: Mr. Foley.

MR. FOLEY: Thank you. My name is Todd Foley. I'm the Senior Vice-President for Policy and Government Relations with the American Council on Renewable Energy. We're a business organization representing the full breadth of the renewable energy sector, all the green technologies, manufacturers, developers, financiers and users and others, including a number of utilities.

I'm pleased to be with you here today to talk about PURPA. I think the timeliness of this meeting is very important as our nation's power markets and traditional way of delivering power undergo significant change. As our nation's generation mix, PURPA remains a very important policy tool that can assist in the development of a more flexible and efficient power generation and grid system to ensure reliable, resilient and affordable power with reduced emissions now and in the future.

PURPA, of course, has played an important role in helping levelize the regulatory playing field and provide access to the market for renewable energy power resources. Renewable energy is low-cost, high-value power. In the case of solar, it's peaking. This is talking about harnessing domestic resources, renewable energy offers locational, T&D deferral benefits, as well as very important emissions reductions. We can have affordable -- in fact, cost advantage renewable power while we reduce emissions.

The voided cost is all about limiting costs, protecting the rate-payer. These methodologies have been very important. But I think they need to be updated. With the advent of new technology, including the increasing cost competitiveness of renewables, and also other technologies and processes that enable more flexible modern and cleaner grid, it's very important, I think, that we look to see about updating the avoided cost.

Guidance from FERC, as well as what the states do. The states are given broad authority in determining avoided cost. But if we can capture the full value and engage in process to capture the full value of these technologies, like demand response, storage, advanced metering, bidirectional communications flows, the lower-cost renewable energy, we can help stimulate private sector development and investment, of these technologies, which enable a much more reliable, affordable and again, cleaner grid as we go forward into the future.

I'd also note that we talked a bit about capacity markets and other values. All of these technologies can do much more to ensure we have the capacity at avoided cost and lower rates. We have the ramping capability, the frequency of regulation and the other key elements of a functioning grid for the future.

There have been a number of important decisions here at the FERC that has enabled the emergency renewables and actually provide some additional opportunity to help to deploy some of these other technologies.

I would note that California Public Utilities Commission decision of 2010, where FERC acknowledged that, in pursuit of state policy, states could also modify their voided costs to compare technology to technology, let's say, wind to wind, solar to solar in advancing. I think these are important precedents, potentially for other technologies and resources that can also help to achieve our grid and power market objectives going into the future.

So just in closing, PURPA has been a very important tool to advance renewable energy, continues to be important and I think it's also very important again, help us update and produce the modern grid that we all need for going forward for the future. So, I'll stop there and we look forward to discussion questions. Thank you.

MR. GREENFIELD: Just take a moment, Mr. Hughes. I neglected at the very beginning to note that we do have several of our Commissioners here, including our Chairman, and I did want to give them an opportunity this afternoon, if they had any introductory remarks that they wanted to make before we got too far along in this particular panel. Chairman Bay?

CHAIRMAN BAY: I don't have any.

COMMISSIONER LAFLEUR: I already gave my introduction this morning. I voted with my feet to come back for more.

COMMISSIONER HONORABLE: Thank you, Larry. If you don't mind, I will wait until after the panel has complete their remarks. Thank you.

MR. GREENFIELD: In that case, Mr. Hughes, the floor is yours.

MR. HUGHES: Thank you. I'm John Hughes. I'm President and CEO of the Electricity Consumers Resource Council, also known as ELCON, and I appreciate the opportunity afforded our organization today.

PURPA Title II is extremely important to the U.S. manufacturing community. It supports the economic viability of the following: Steam-driven industrial sectors, Agricultural products, Building materials, Chemicals, Food processing, Glass, Mining, Oil and Natural gas, Paper and forest products, Pharmaceuticals, Rubber, Steel and Textiles.

It's a huge swath of the manufacturing capability of the United States. My comments will address

ELCON's assessment of how PURPA is working today, our thoughts on avoided cost methodologies, and several recommendations for the Commission's consideration going forward.

There's no question that PURPA works and the Commission should resist changes to its regulations implemented the in 1978 Act that amount to the repeal of the Act. Our concern is that attempts to limit regulatory arbitrage, and I use that term rather than gaming, associated with avoided cost payments may result in other reforms, imposing collateral damage to the huge existing fleet of industrial QFs with a proven track record as highly efficient, reliable and clean energy resources, over 60 gigawatts of combined heat and power, or cogeneration, as I prefer to call it, was developed in the U.S. since PURPA's enactment.

The vast majority of it is industrial QFs and industrial cogeneration is a technology that other people have spoken earlier, is embedded in the industrial process, is part of the load. The mandatory purchase obligation, where applicable, and supplementary backup and standby power services had just and reasonable rates, are even more important today than when PURPA was enacted. Industrial QFs are impossible without these essential services.

If the claims of QFs are locking in buy-back rates that exceed avoided cost and that the capacity from these resources are not otherwise needed or true, then it reflects a failure of state regulators to properly implement PURPA, not a failure of the law itself.

As PURPA has explained, "In order to maximum the incentives for QFs, the Commission sets the price per purchases from QFs, absent negotiations at a statutory ceiling. Thus, the avoided cost rate is neither more nor less than the price the utility would have paid for comparable power from other sources, including other wholesale sources."

The entitlement of QFs under PURPA and FERC regulations to payment of rates based on the utilities' full avoided cost, and not a lesser rate, unless the utility and utility mutually agree, was upheld by the United States Supreme Court and the American Paper Institute Supreme Court case.

States can obviously do a better job with avoided cost calculations. This is not rocket science. Uncertainties abound in everything the utility does, including new additions to their rate base, or the setting of customer rates. PURPA and the FERC regulations already prohibits states from using avoided costs as a policy tool to discourage economically viable resources with rates that are below avoided cost or to encourage or subsidize uneconomic resources with rates that exceed avoided cost.

It is time to enforce, not change PURPA's and FERC's regulations. ELCON members are also increasingly diversifying their deployment of distributed energy resources that are qualifying small power producers at capacity ratings below 20 megawatts.

These resources typically are biomass, waste or other forms of renewable energy, and should qualify under Order 688 rebuttable presumption that it does not have discriminatory access to wholesale markets and is eligible to require the electric utility to purchase it.

In conclusion, I want to recommend the Commission to consider the following three recommendations. And they have nothing to do with the main issues that were discussed in the first panel. And so we're sort of silent on that.

First, the Commission should issue a Policy Statement reaffirming its support for PURPA. Specifically, the Commission should reaffirm the original intent of the Act to promote cogeneration and certain small power renewable producers.

The Policy Statement would help the Commission rationalize its policies and regulations, implementing PURPA, in the face of the dramatic changes that are taking place in the industry right now, including when and if the

Queen Power Plant is implemented.

Second, the Commission should direct its capable staff to prepare a guidance document on the applicability of the various avoided cost methodology. The audience for this document would be State Commissions and utilities.

We do not believe that there is one best method and it is important that states be given maximum flexibility to fulfill their statutory responsibilities under Title II. Staff guidance would include as an assessment of the pros and cons of each methodology, best practices and options for addressing the price anomalies that exist in wholesale markets created by federal subsidies.

Third, the Commission needs to acknowledge that its implementation of Section 210(m) is flawed and at least in part responsible for the huge drop-off in new cogeneration development beginning in 2005, the year Section 210(m) was enacted.

The Commission is urged to require its jurisdictional ISOs and RTOs to offer a standard QF tariff that a QF may use optionally to more easily access the bewildering arrays of energy and capacity services that are available in the organized markets.

I fear that otherwise you're going to relegate to some poor schmuck at a factory that has the responsibility of selling this power to become the PhD in operations research, so that he understands what virtual bidding and long-term FDRs are.

In open access states, this might include the procurement of supplemental backup and maintenance power and providing a self-supply capability and with the surplus power from one site can be used to offset purchases off the grid at another site of the same company.

Given the short-term nature of organized markets, the tariff cannot offer published fixed rates or these services. The tariff could be structured to accommodate both "as available" power and transactions that can be scheduled in advance. The intent is to provide the QF with a more user-friendly interface with these markets forcing QFs to be experts on the market design, violation of spirit, if not the outright intent of PURPA, to promote clean and efficient technology. Thank you for your attention, and I look forward to the discussion.

MR. GREENFIELD: Commissioner Kavulla?

COMMISSIONER KAVULLA: Thank you very much for having me. I'm Travis Kavulla. I'm the President of the National Association of Regulatory Utility Commissioners, as well as the Vice-Chairman of the Montana Public Service Commission. I guess I can add another hat to that. I'm a member of the California ISO's EIM Transitional Committee for the next two days. Before the EIM Board is actually seated and I, along with a number of other Commissioners in the West, have expressed great interest in creating more efficient and robust wholesale markets for generation.

Thank you for having a number of state representatives here today as the federal judiciary has often affirmed, its states that play the primary role in calculating avoided costs rates. And so if it's done well or poorly or not at all, it is our fault, or to our credit that we do those things. I think all roads, to some degree, lead back to the accurate calculation of avoided costs, which is a very hard thing to do.

And that's why flexibility in your administrative regulations implementing PURPA and your direction to the states, is an essential element of the regulations as they exist today and something we hope to persist over time. There may be changes that need to be made with respect to the mandatory purchase obligation, but in general, the flexibility conferred in the calculation of avoided costs regulations is satisfactory to most states.

Most states attempt to mirror their avoided costs calculation methodology to how other generators in the marketplace are compensated, and in general, there are three marketplaces through which generators earn revenue in the United States. There are those regions where it is expected that the centrally clearing markets of an RTO or ISO provide a sufficient number of products to create a revenue stream sufficient for generators to be compensated for their entry and operations in the market.

There are those places which have centrally clearing markets, but really operate more as an optimizing function, an overlay, if you will, to long-term procurement through contracts or utility self-billed, and where cost of service regulation is still the predominant model and generation is included in rate base of regulated utilities by State Utility Commissions and finally, there are those utilities that own or contract for the vast majority of their customer needs outside of an RTO or ISO, but on bilaterally transacting wholesale markets for the disposal of their excess energy or purchase of energy deficits.

The avoided costs calculations with respect to PURPA, for states, are generally a mirror image of how those larger, more dominant generators in any given market, are compensated. And so I think most states in the first type of marketplace would simply say, "Why don't you just take the clearing price, whatever it happens to be," as other generators would. If there's a problem with transactive frictions, like Mr. Hughes pointed out, there's surely a way to unlock those transactions, even while not getting away from the price discovery that happens in the marketplace, rather than in an administratively determined avoided cost.

But with respect to latter example and in the Western interconnection, in particular, it's typical for regulated utilities to rate-base their generating assets with rates established to permit the capital investment in those plants to be returned through depreciation expense an annual return on the undepreciated balance of investment and operating costs.

These rates provide a long-term revenue guarantee, or something close to it, to the utility, irrespective of whether their plant in the long run, will have been an above-market or below-market investment.

Utilities instead rely on a central planning exercise, typically known as integrated resource planning, or IRP, to make a judgment at the outset. Relative to a long-term market forecast and a survey of available alternatives that the investment is efficient compared to those alternatives.

Regulators have been -- IRPs conferring a signal for the likelihood of cost recovery or pre-approved new plants directly or grant them rate-base status shortly after their construction. Most state regulators in the Western interconnection have thus traditionally offered QFs a similar opportunity for long-term contracts with avoided costs calculated at the time of a legally enforceable obligation or at the time of the first delivery of energy and capacity onto the grid.

Nearly two decades ago, NARUC resolved that PURPA's mandatory purchase obligations and long-term avoided cost rates that are administratively set, should not exist "in any state which is made a finding that the acquisition of generating capacity is subject to competition or other acquisition procedures, such that the public interest is protected with respect to price, service, reliability and diversity of resources."

In the meantime many, many markets have not only had huge growth in renewables, but they have also had more competitors in the generation space, even while requiring less new plant to meet anticipated load growth and existing plant retirements.

In light of this, FERC could adopt interpreting regulations that either effectively relax the mandatory purchase obligation or make it clear that shorter term avoided costs calculations are acceptable for PURPA compliance in certain circumstances which are indicative either of an absence of need for new plant, or evidence of sufficiently robust competition and wholesale generation.

And I offer three examples here and in my written comments. One, where solicitations are routinely held and genuinely competitive for the needs identified in the utilities' IRP, where utility in its IRP does not forecast the need for an additional owned or long-term contracted energy resource for a period of time, such as five or seven years, or where a centrally clearing energy market is operational and importantly, where clearing prices and/or bids in that market are not subject to market power mitigation of cost. Thank you.

MR. GREENFIELD: Commissioner Raper.

COMMISSIONER RAPER: Thank you, Chairman, Commissioners and Commission staff. I appreciate the opportunity to speak. My name is Kristine Raper. I am a Commissioner with the Idaho Public Utilities Commission. I know who is friend or foe by whether they call me Kris or Kristine.

Let me begin by saying some things that might surprise you, based on other assertions made by parties here today at this Technical Hearing. Idaho does not believe that PURPA is obsolete. We're also not asserting that PURPA is wrong. We just believe it's being abused.

So State Commissions need the tools to be able to deter the abuse of the written law in the FERC regulations. We have many small, mostly run-of-river hydro, PURPA QFs and projects that we believe are precisely the type of projects that Congress envisioned when they wrote the law.

What I would wager Congress did not intend was large corporations and renewable parts manufacturers and, in at least one Idaho contract, Italy to get rich at the expense of rate-payers. We've tracked one contract back to Italy being the ultimate owner of the resource. As you well know, avoided costs are calculated numerous ways across the U.S., and I would encourage this Commission to continue to allow discretion to the states in calculation of avoided costs.

While there have been assertions to the contrary, it is our position, it has been our experience that, regardless of how avoided costs are calculated, long-term contracts inevitably work to the detriment of rate-payers. In Order 69, this Commission recognized that avoided costs calculated when parties enter into a PURPA contract, could result in future avoided costs, during the term of the contract, being greater than actual avoided costs at the time of the delivery. And the Commission actually acknowledged that in those cases the rate-payers would be subsidizing the QF industry.

Now, this Commission reasoned that over the long-term, that the high-priced contracts and low-priced contracts would equal out, but that has not been Idaho's experience. No matter the starting point, allowing QFs to fix their avoided cost rates for long terms results in rates which will eventually exceed and overestimate avoided cost rates into the future. The longer the term, the greater the disparity.

So, as you heard at length this morning, the Idaho PUC recently reduced PURPA contract lengths to two years in order to correct the disparity. We didn't reduce contract lengths to kill PURPA. We did it to allow periodic adjustment of avoided cost rates.

And in all other ways, these contracts are functionally equivalent to the 20-year contracts that those QFs had prior to. They become part of the resource stack once they begin generating energy. They establish their entitlement to capacity. They can renew indefinitely because of the mandatory purchase obligation.

The only thing that this changes is the avoided cost rate so that at incremental opportunities, it can be corrected to actually reflect the avoided costs that the utility is incurring by accepting the QF resource. And this is so that rate-payers are not harmed.

I appreciated Commissioner Clark's reference earlier. I think it was something about our pure interest at the Commission. If I'm wrong, don't correct me on that. I like the pure interest and the whole white hat approach. So my halo might be glowing.

We at the State Commissions do not have enough tools in the toolbox. An ideal solution for our situation would've been to allow 20-year contracts with periodic updates in that avoided cost rate. Our interpretation of FERC regulations is that when a QF ops to elect an avoided cost rate at the time that they enter into the contract, that that is the constant avoided cost rate throughout the life of the contract.

If it's different than that, if FERC believes differently, then that's something that the Idaho Commission would consider in looking at contract length. But it truly was our intent to simply have an accurate reflection going forward of the avoided cost rate to the utility to be paid to the QFs.

PURPA does not have to become a dirty word heralded only by clean energy advocates. But the State Commissions need this Commission to allow the states' discretion based on local circumstances to effectively and reliably manage the grid, implement PURPA and ensure that rate-payers are not harmed. Thank you.

MR. GREENFIELD: Mr. Rose.

MR. ROSE: Thank you very much for having me here today to talk about this important issue. Some of the points have already been taken, but I'll just outline some of the things that I have in my written remarks.

In my view, PURPA has held up reasonably well over the years and it's hard for me to believe that almost forty years later, we're still working on implementation of PURPA. I think in some ways it's been adapted as times have changed over that thirty-eight-year period where the Commission has adapted, the Congress has changed the rules, and of course, the states have adapted and changed the rules as they've gone along, so --

PURPA provided kind of a general outline that I think still works today. And so I think overall it works pretty good. So, primarily one of the goals of PURPA, I think is still relevant today, which is really preventing utilities from refusing to interconnect with and fairly compensate small power generators. They use renewable energy and cogenerators, or CHP, that want to sell power to the utilities. I think that's still a relevant factor today, even though technology has maybe caught up with some of this.

In this panel, in particular, what is designed to talk about the methods of calculating avoided cost, and I don't think there's really any significant changes that this Commission really has to do. The Commission has already prescribed guidelines for states and nonregulated utilities to follow, which are appropriate in my view.

And they haven't really specified, and shouldn't in my view, methodologies that calculate avoided costs. I think that's a little bit too far down in the weeds for this

Commission to be involved in and is generally a state issue.

The Commission rules provide definitions of avoided costs, what avoided costs are in a general way. They require data to be available to calculate avoided costs. They define the obligation to purchase, identify factors to be considered when calculating the avoided cost. And I think those are all appropriate still today.

The Commission hasn't prescribed a cost methodology, so I don't believe that they should start now or it's required. This Commission has generally left to the states and not regulated utilities to determine that avoided cost pricing, and I feel compelled to quote Justice Brandeis, the famous quote about, state as laboratories, because if you look across the states, they all have dealt with PURPA in different ways over the years, and I think that is a good thing.

They learn from each other. They follow what other states are doing and adapt to the changes, and I think will continue to do that even when there's problems in the implementation. Generally, the states are the ones that are going to fix it from their perspective.

In 2006 the Commission, of course, implemented the changes under the Energy Policy Act of 2005 and the Commission allowed determination of the Utilities Obligation to Purchase Power from a Qualifying Facility, recognizing of course the changes that have been underway in those so-called organized markets, particularly ISO/RTO markets.

There was a lot of discussion this morning, of course, about the exception to that for the rebuttable presumption that qualified facilities with capacity at or below 20 megawatts do not have nondiscriminatory access to eligible wholesale markets. And I would argue that the Commission, if you decide to revisit your PURPA rules, that you maintain that and keep that 20-megawatt rule.

I was listening to the argument, I know it was talked about this morning, but I think it convinced me further that probably just keeping it where it's at would probably be the best thing for right now.

If I could just add one thing that I don't think was talked about too much this morning was, in working with relatively small QFs it's pretty clear they're really not -- and I think John Hughes was saying this, too -- it's really difficult for them to deal with these RTO/ISO markets that have gotten very complex over the years and in fact, have only gotten more complex.

And we're talking about some QFs that are only 1 or 2 megawatts, they're very small, but even up to and certainly less than 20 megawatts, you're talking about a lot of expense and experience that's needed in order to deal with the market, that the utilities have to deal with themselves.

In fact, when I first heard about this difficulty was from relatively small utilities that have to hire new people in order to be able to operate in these markets. A QF that is in a different business maybe than just selling power, this is going to be more of a burden for them. And again, I expect that those markets will only become more complex over time.

That's probably maybe the subject of a separate Commission Technical Conference, just talking about the market complexity. So there's nothing -- if I can echo Mr. Brogan's comment -- there's nothing in the Commission's regulation that requires any utility to pay more than the avoided cost. And I would argue that not only shouldn't you not do that, but I don't think you can. That would be a clear violation of PURPA.

So we're only talking about trying to use the avoided cost methods to come up with a fair evaluation of what is the avoided cost of the utility. And I think you have to guard against utilities trying to now use the current market conditions to evade the responsibility under the law. So it's really a balancing act to make sure that they're fairly compensated, reflecting the utilities' avoided cost, but at the same time, you're not overcompensating, I mean causing problems for rate-payers down the line.

So I think PURPA requires State Commissions and nonregulated utilities to comply with the Commission's rules. That's there now, but I would urge you to keep that backstop authority that FERC now has when there's kind of a dispute within the state. And I think that should maintain that role and maybe even try to clarify that if there is a revisit on the rules. Thank you.

MR. GREENFIELD: Mr. Sipe.

MR. SIPE: Thank you. My name is Don Sipe, and I'm here representing the American Forest & Paper Association. I think Mr. Bloom covered this morning the distinction between CHP and the other resources we're talking about, so I won't get into that on this panel, although most of the people that I'm here representing, that's one of their major concerns.

I do think though that in any case, getting avoided costs correct is paramount to protecting rate-payers, but also to getting the right investment signals. So I think I want to begin with some general observations about the role of avoided costs and the context where they come up that I hopefully will frame sort of my reactions to some of the other suggestions that have been out here.

There is always risk in any investment. It doesn't matter what the investment is, doesn't matter who makes it. You're not going to avoid risk in investment. I've heard people say that we set avoided costs and they're always wrong. Well, surprise, surprise. Okay?

That is the nature of trying to predict the future. The future responds to your predictions and everything that you said as a bogey, that's what the market is setting as a bogey to beat, or someone else is. So it shouldn't surprise us that we have these mismatches moving forward.

The question is, is it truly avoidable and do PURPA contracts, in particular, pose any special risk that's different than the risk if the utility faces is doing anything else. Now, if they're set properly, and let's just assume that they can be set properly, these avoided costs ought to look like the planning assumption.

They ought to be looking like what the utility's using to plan its own investment. How else are they figuring out what their avoided cost should be?

If that's true and they're wrong, then they're just as wrong for the utility investment that's proposed instead of the QF investment. It's not like this is a one-way street. If they've got it wrong, they're doing their utility planning wrong.

And those costs are on a long-term contract.

Once utility bills something, they've got a long-term contract with rate-payers that's going to get them recovery for that. It's no different than when they sign up with a QF. So, if they're looking at a full picture of their needs, they're predicting future energy costs, they're predicting their future capacity costs, they're predicting where the market's going to go, and they're making some assumption.

Now, if we're coming in below those assumptions, we have probably a better chance of being right than they have working on their own assumptions building their own plant. Now, I want to move from there, because that's the simple examples, when the utility's building.

But there is this sort of idea that there's a free lunch per risk if we go to the market. You know, I find this sort of ironic, coming from New England, where I've got people going out of business because the market will not invest in needed infrastructure of various types that we need to have up there.

You know, markets do not relieve consumers of risk. They repackage it. And the risk premium in the market reflects the general failure rate. It's true, you are protected from the risk of loss on a particular project, but you are not protected from risk if you rely on the market instead of a long-term projection under a contract.

You are getting the general failure rate. And you are also assuming the risk that things that should get built just do not get built. And those are fairly significant risks in various parts of the country.

If you have a long-term energy rate that appears to be above-market or is above-market, you have a visibility problem more than I think a differential risk problem. The utility's bad investment is down on its rate base. It's covered up with the fuel cost and the fact that they're not running that plant that they thought they were going to run, but you're still paying the capital costs, is not out there visible to the world.

But if they have planned this right, they would've planned that plant, based on what they thought they were going to get for energy and capacity and comparing it to your project, which means that implicitly there's an energy price to that plant.

If there's not, they're not doing planning correctly. And they've made a long-term investment based on that price. If they're wrong, they're wrong for both projects.

Getting avoided costs right, I think is going to answer a lot of the questions that we've got. And I think that is important, and especially things like gaming. You know, from a consumers' point of view -- I was listening to the "one-mile" discussion this morning and somebody said, "Does anybody want to support gaming?" And I'm thinking, gaming implies to me that somebody's taking my money. Okay? It doesn't imply to me that somebody's trying to use the rules to get me a better deal. That doesn't sound like gaming to me.

So I hear that we've got a "one-mile rule" and the problem is that somebody's siting a project that's bigger than what somebody else thinks it should be, based on that, which I think is a reasonable rule. You know, one-mile, you've got to put it in the statute somehow.

And the big problem is, is that a next project is lower than the utility's avoided cost. I'm a consumer. I'm thinking, how is that gaming me? What is it that I'm being deprived of by having that other project within a mile? I mean as a consumer, maybe I'll propose a half-mile rule. Because essentially, what we want to see is, we want to see the projects built that are the lowest cost, that have the best chance of working out in the market.

Now, you sign a long-term IPP contract. That contract is got a variable energy cost in it. There's nothing you can point to when you say, "Oh, gee, that energy price went up from where we thought it was going to be when we signed it originally."

If we have a problem with declining avoided costs, we ought to figure out a way to work that into the calculations. We got to figure out a reasonable way to reflect the fact that we think avoided costs are declining, and to have rates that reflect that. That doesn't sound -- well, it is rocket science. I mean, predicting the future is rocket science. I mean, who said it wasn't?

This is going to be difficult. But, it's not just difficult for QFs. Okay? That's the point. It's -- they're making the decision based on the same calculation. And if they can prove to me that their decision-making is based on an estimate of defining marginal costs, so they aren't building this or that on their own, and everybody has to beat that price, so beat it. We'll beat the price. Thank you.

MR. GREENFIELD: Ms. Whittle.

MS. WHITTLE: Good afternoon. Thank you, Commissioners and staff for calling this Technical Conference today and for including my group, the New England Small Hydropower Coalition in the panels. Just to tell a funny QF story, I may not be the oldest person here, but my father, who was a retired energy lawyer, worked for the Federal Power Commission in the '60s, filed QF80-1, which I think was the first QF and it was a small project in Massachusetts that I understand is still operating today.

I learned by osmosis, I suppose. I also used to watch Commission meetings on his VCR tape when he would bring them home. Fast forwarding all the time. Don't tell him I said that.

But I'm here today on behalf -- and my name is Elizabeth Whittle, by the way -- and I'm here today on behalf of the New England Small Hydro Coalition, and it consists of the Connecticut Small Power Producers Association, Bay State Hydropower Association, just Massachusetts, Granite State Hydropower Association for just New Hampshire, and the Vermont Independent Power Producers Association.

This group represents more than a 140 small hydro projects located in the four New England states with a total installed capacity of 183 megawatts. Almost all of the projects are 5 megawatts or below. All of the projects are 20 megawatts or below. They're all QFs and they all operate under FERC Hydroelectric licenses or exemptions.

As a result, these projects have, not only do they have to participate with utilities, but they also have stringent terms and conditions of their licenses that restrict a number of things, including many of them are run-of-river, which means they can't store energy for generating during peak periods and that sort of thing.

The New England Small Hydropower Coalition exists because individual small hydropower projects simply don't have the resources to participate in these legislative and regulatory processes at the state and federal level that determine how QFs will be regulated and paid. Each of the organization participates in the local state agency as a group, and then they've come together to sponsor today.

The group appreciates the opportunity to speak on the importance of the protections of PURPA in today's environment. Unlike some entities participating in the Technical Conference today, our group are principally concerned with PURPA and the Commissions' regulations implementing PURPA as they apply to existing projects.

The vast majority of these facilities were constructed in the 1980s and early '90s and have operated under long-term contracts that have recently expired. These projects have been in existence and operate pursuant to the terms and conditions of the license, which I mentioned. Lots of historic operating histories and are very reliable participating entities in the local regions where they operate.

As I noted before, most of them are required by their licenses or exemptions to operate in run-of-river mode, which means water input must closely reflect to water output. What comes in goes right through. If they're not generating, water is spilling over the dam.

The Hydropower Coalition supports continuation of the mandatory purchase obligation, especially for small projects without access to competitive wholesale markets. Without the mandatory purchase obligation, many of the hydroelectric generators would have no means to sell their project power. They do not have access to ISO New England, and even if they did, the costs and related operational requirements are additional and significant impediments to their participation.

With respect to avoided cost rates, the purpose of this afternoon's panel, our coalition supports the continued availability of a calculated avoided cost rate available to QFs on a long-term basis. As we've all been talking about today, the energy markets have changed substantially and in New England, that is absolutely true with the creation of ISO New England. It's an RTO.

Some of the utilities in New England have divested their generation. Some of the utilities in ISO New England have not, which creates another complicating factor for determining avoided cost.

Prior to establishment of the RTO markets, we had the, I think, what we see in the West is a more structured way to determine what the avoided cost rates are. But in the RTO states, many of the State Commissions have determined that the avoided cost rate is the hourly real-time L&P.

While there are many ways to calculate the avoided costs, the proper avoided cost rate, the hourly real-time L&P is an inappropriate proxy for avoided cost, because it doesn't reflect the true avoided cost to the utility under the Commission's regulations and PURPA.

First of all, most purchasing energy in the RTO markets purchase nearly all of their power in the Day Ahead Market. At the Day Ahead L&P. L&P rate doesn't take into account any long-term or seasonal purchases made from third parties or affiliates.

I just wanted to say we have three asks from the Commission. One is to update the definition of avoided cost to reflect the utilities' true avoided cost of energy is not the locational marginal price. We want to reaffirm the rights of QFs interest to long-term power purchase agreements at an avoided cost rate established at the time of the legally enforceable ligation, and more vigorous enforcement of PURPA. Thank you.

MR. GREENFIELD: Mr. Wise.

MR. WISE: Thank you, Mr. Chairman and Commissioners, staff. My name is Michael Wise. I am the Senior VP of Commercial Operations and Transmission for Golden Spread Electric Cooperative. I'm responsible for the forecasting, the resource planning, the market operations, the regulatory and transmission policy, all of this utility.

And I thank the Commission for the opportunity that you've afforded me to speak today. Appreciate it very much.

By way of introduction, Golden Spread is a nonprofit generation and transmission cooperative. It supplies wholesale power to its sixteen-member distribution cooperatives in Texas and the Oklahoma panhandle. We serve 25% of the landmass of Texas, although we probably serve more cows than we do people, out in that area.

Most of our territory is located in Texas, in both the Southwest Power Pool and the Electric Reliability Council of Texas. About 80% of our load is in SPP and 20% in ERCOT. And so my comments, my remarks will be basically isolated to fully functional Day 2 Market structures that are operating quite well.

This territory that we're in is actually what I call the Saudi Arabia of wind. Amarillo is the center of the wind universe and it seems to be that substantial amounts of renewable energy is actually interconnecting as we speak and generating superior annual capacity factors.

So we are in that sweet spot for solar and for wind renewable energy. It's largely because of the prevalent high wind speeds in this optimal photovoltaic activity that we have out in that neck of the woods and particular part of the United States.

As to avoided cost methodology, Golden Spread agrees with the precedent set in Texas which establishes two fundamental principles. First that the utilities' avoided cost for energy is the cost it would otherwise pay for that energy from the market at the time of delivery. That is, that the market's real-time locational marginal price.

Second, QFs that generate intermittent power, such as solar and wind, do not provide sufficiently firm service to allow them to compel a legally enforceable obligation. This essentially argues really for allowing the competitive markets and the RTOs anyway to establish the avoided cost.

With this avoided cost factor op, it is the SPP and ERCOT markets that are best suited to determine the type and the quantity of resources needed to serve consumers with what I call optimal economic efficiency. They operate to pool resources and loads together to meet in response to market price signals.

Since the 2005 PURPA reforms, ERCOT and SPP have undergone drastic changes as you all know. Specifically, with the SPP and the leadership of the FERC and pushing and encouraging RTO functions and the development of the stakeholders in the SPP, which I was a part of during that time, very proud to admit that. We took those signals and we collapsed the sixteen balancing authorities into one single balancing authority, and also developed a Day 2

Market structure. We have a Day Ahead market, a very functional Day Ahead market, where 99% of the load is cleared in that market. And a highly effective real-time balancing market as well.

So that market is functioning quite well. In fact, what happens is unit commitment is no longer at the individual utility. The world has changed. The individual IOUs, utilities that we think as the bad guys many times, they no longer can commit the resources or do commit the resources. They can self-commit, but it's economically not justified in many cases.

So the unit commitment authority moves up to SPP at the RTO. And it's in a unit stack basis, and the most efficient generation actually operates for the good of the pool.

So you've got this situation, we have sixteen BAs collapsed to one. We have fourteen states now with 52,000 megawatts of peak load, all pooled together, such that the resources and the loads can come together and find the economic clearing price for that energy, providing real benefit to the consumers.

In fact, I think we heard from the SPP staff just recently that the benefit to the consumers in this pool has been in the order of 420 million dollars on an annual basis. So this is real savings for consumers, which we're all about. So it's exciting to see what we're doing there. We think that this really does change the framework of talking about avoided cost.

These are open and integrated systems with independent market monitors, market price is dictating that resources are dispatched based upon the economics and security constrained economic dispatch reliability issues. Each of these markets have invested several billions of dollars. In SPP it's ten billion dollars that has been approved and has been built and is being built and ERCOT's about seven billion dollars that's largely supporting this huge set of pools of resources and loads and the concept that I've just indicated to you.

QFs of all sizes now have what we believe is unfettered access to these markets and can participate in them along with all the other suppliers on an equal footing. FERC requirements should be modified to recognize this reality. Otherwise, the competitive outcome becomes distorted. The Commission should reduce to a megawatt or even lower, the 20-megawatt threshold as it applies, to establish the presumption that QFs have access to the markets. I know that's not popular to some on this panel.

Alternatively, the Commission should reform the capacity purchase obligation. Capacity is treated differently in different markets and its value varies greatly by year, and by the type of generation resource. Forcing a utility to purchase capacity at a fixed price over a term of several years, from a specific type of resource imposes significant risk upon the utility and its consumers.

At a minimum, the Commission should reduce the maximum term of the legally enforceable obligation. A term of one year would recognize that there are short-term capacity options available in the marketplace right now. And the longer term planning arrives and is too speculative to impose longer term fixed price obligation.

So in conclusion, the Commission -- hopefully we keep in mind that PURPA was never meant to be applied in a manner that harms consumers by forcing inefficient higher cost outcomes or shifting market risks onto load serving entities. Thank you.

MR. GREENFIELD: My thanks to all of the panelists and I would like to start with Chairman Bay and the other Commissioners, and I would again remind the panelists, when you are responding, make sure you do speak into the mike, which sitting here I noticed is going to easier for the people on my right, a little tougher for the people on my left because of the angle, but do try to speak into the mikes if at all possible. Thank you. Chairman Bay?

CHAIRMAN BAY: Thank you. So in implementing

PURPA, FERC, in my view, was respectful of principles of cooperative federalism, and so to a large extent with respect to the calculation of avoided costs, FERC deferred to the states. And so, to the extent that there's a problem here with avoided cost and a number of panelists have indicated that they think there is a problem with the calculation of avoided cost, is that a problem for FERC or our regulations or is it really a problem that we should defer to the states to resolve? So that's really one of the big questions that I'm trying to grapple with. So I'd appreciate hearing the views of any panelist on that issue.

MR. SIPE: Thank you. I think that FERC is always going to have to have an important backstop role. You can defer your authority and try to be cooperative, and I think someone on an earlier panel said it's a two-way street. I think that the arrangement of allowing states in the first instance to set avoided costs, I think is a reasonable approach.

When we looked at the various methods of doing avoided costs, they all seemed like they could be amenable to a reasonable result if people took them seriously and they were using them for their own planning assumptions. And there's not one way to predict the future that we think is right, so I think that variability is good. But I think that you should be open to claims where there are avoided costs calculation or other methods that clearly defeat the idea of encouraging QFs. And I think that that's sort of where the line is, and it's a judgment call, and it's probably incumbent upon individual QFs to bring those to you, or organizations where they think that happens.

So I don't think you can avoid that backstop role, but I think that a variety of avoided costs, things that we've seen out there, they all seem like they would be amenable to a reasonable result if the utility was using that same way of predicting the future. And if they could all be fair and be flexible enough.

MR. BURLESON: Yes, thank you. Mr. Chairman, I just wanted to mention that for us, the avoided costs aren't just the avoided costs that we pay QFs, but we use those avoided costs for a number of other purposes within the company. And so I think within our four states, the calculation, the determination of the avoided cost, we believe is good.

The issue here really is, that I referred to in my remarks, is really the issue of "do we need to lock in a long-term projection of those avoided costs?" So it's not so much the calculation, but it's the requirement that we either allow QFs to take, as generated, avoided cost when the energy's delivered, or the projections when a legally enforceable obligation is entered into.

That's really the crux of the issue. And I think the example that I'll give, if we think about our own planning, if we have in any way understated our projections of avoided costs, we use those same avoided costs to study retirements of co-units, gas units, nuclear units, then we would retire more than would be most appropriate for our customers.

If we overstate the avoided cost, we would wind up taking other actions, such as implementing energy efficiency at levels that would not be cost-effective. So we use those across all of those spectrums. The issue is, again, the projections. And the challenge for us is, for traditional generating resources, we don't have a 100% of the cost obligation of those resources locked in.

So as an example, if we're planning our system and we're planning combined cycle natural gas generation, of the total cost of that gas generation, over its life, probably something like 40% of that is fuel cost in variable operation and maintenance. And that is avoidable for us, even after that unit is built. If it's a coal plant, it's a similar situation there, probably 60% of that total lifecycle cost is avoidable.

But when we lock in long-term projections of avoided cost for the QFs, none of that is avoidable, because a QF can put all of that energy on us, and I think that is an issue for this Commission to consider addressing, because that is one of the requirements today as we either offer them avoided cost at the time they deliver the energy, or projections of avoided cost at the time the contract's entered into.

CHAIRMAN BAY: But, Jeff, isn't that the risk with all longer term contracts? That you're locking into a certain price? And I think this was Don's point, actually, so I mean it's possible to imagine a thought experiment, where if you entered into long-term contract in 2006, prior to the Shell revolution and let's say it had a price of $40 per megawatt hour, the Shell revolution hadn't occurred and wholesale prices were now at $50 per megawatt hour, I just wonder how many people, who are complaining about the longer term nature of these contracts, would be complaining about them today? I mean, isn't that what happens with respect to market risk?

MR. BURLESON: Yes, there is a risk there with long-term contracts. I think the way that we mitigate those risks for our customers is, we typically don't lock in, except for QFs, those long-term projections of avoided cost. So if we enter into a bilateral contract with an independent power producer for combustion turbine or combined cycle capacity, we don't fix the energy price. The capacity payment is a fixed payment. That's their fixed revenue strain.

The energy price is typically indexed to the price of natural gas. We can dispatch around that energy price with other resources for those dispatchable kind of resources. With QFs, we can't dispatch around it. So it's 100% of that QF contract obligation is borne by our customers and so that's the differentiation there.

MR. HUGHES: I think I'll just repeat what I said in my opening remarks, that the states clearly need some better guidance on how to use the methodologies, including the process by which the methodologies are used, and how the numbers that fall out of the methodologies are consistent with what goes on in a retail rate case proceeding for the allocation of risks and costs to rate-payers.

I think Don mentioned that you put something in a rate-base, and that's a long-term contract with your rate-payers, and it's a -- there could be a lot of risk associated with that. It had nothing to do with the matters we're discussing here. You know, some utilities recently have been building nuclear plants that are just grossly overpriced.

Those final costs may not all go under rate-based, but what will go under rate-based is your proverbial pig in a python. Others have been building integrated gasification combining cycle plants that are equally grossly out of align with the market price for power.

And so it seems to me, somewhat disingenuous that rate-payers shouldn't have the risks of the long-term contracts associated with the QF capacity and/or energy. You know, but they bear all the risks associated with the long-term obligation that their utilities made. You know, for somebody it's very high-cost, the generation assets.

So there's got to be some consistency here in how that is handled. You can't do one one way and the other another way and say it's rate-payer's benefit.

MR. GREENFIELD: Commissioner Raper.

COMMISSIONER RAPER: With regard to your question about whether correct avoided costs or bad avoided cost is the state or FERC's problem, I think states need to determine a good avoided cost. I actually think Idaho has a really good structure for their avoided cost. We have a published rate, which is your standard rate that's required by FERC regulations. We also have an IRP-based rate. The problem enters in, consistent with what Jeff with Southern Company said when those things are manipulated.

In long-term contracts, the rates that are good today, the avoided costs that are reflected today, are not reflective going forward on a long-term basis. And gaming comes into that, too. So we have a 100KW or a 10 average megawatt threshold for our standard rate contracts. But you have a 100-megawatt Shell oil come in and break up into five 20-megawatt facilities.

They then get this published rate, and Ms. Chapelle got to it earlier, on the earlier panel. She was talking about her small facilities, these small facilities that need the assistance in contracting, in getting things through, in getting this taken care of. And they can't afford to jump through the hoops and figure out all of the details, and I think that FERC recognized that in their regulations, by setting a 100-kilowatt threshold.

But when you have the large builders coming in and trying to get in under a standard rate, then that standard rate, which we believe we fairly set for small facilities, is not an accurate reflection of the avoided costs that a larger facility ought to be obtaining.

So your second issue that was brought up by, I believe, Mr. Hughes, as far as contracts go, whether it's the contractor, the QFs contract going forward, when a utility builds a utility-scale project, they have to prove to the Commission in their state that that energy is necessary and used and useful.

They have to go through and get a Certificate of Public Convenience and Necessity in our state. They have to prove that the energy is going to go somewhere and that the customer needs it and that they need to provide it in order to provide reliable service.

And a QF comes on at 20, 40, 60, 100, 120 megawatts, and they have nothing that they have to prove to the utility, the customer, the Commission and the state. In fact, we don't even have the right to look at their books. So, you know, when you want to compare what the utility is getting as a return versus how much it cost the QF to build their facility, and as far as contract length goes, which is the current argument in our state, how long of a contract does a QF need in order to be able to finance its project? The answer is, I have no idea. Because I don't have access to their books and they don't have to provide them. So, you know, it's not an apples to apples comparison to the utility.

MR. FOLEY: Thank you. Mr. Chairman, I'd say that, of course, you know, the system hinges on cooperative federalism, just as you said. And I think there's an important role that can provide in providing some guidance, especially on what's happening in the markets with the increasing cost dependence and other developments and new technology that enables more flexibility in our markets.

I do think that, when it comes to contracting, you know, we -- integrated resource planning portfolio management really is key. Mr. Burleson noted that, of course, that there are fuel costs involved in conventional procurement, but we just note that with regard to most renewable energy resources is that, it's not front capital costs, but there's, you know, virtually no fuel costs in most cases.

So, you know, when you think about, you know, looking ahead at the future and we've talked about that a little bit today, that is hard to predict, but there are some very important metrics and we'd be happy to provide more of that in our sector to help support very accurate avoided costs calculations that we can.

I think, you know, it is, of course, true as we're acknowledging here that, you know, utilities and others are signing long-term contracts and they're taking the best look they can with the information they've got now. Just like, again, our personal portfolios make sense to build in some flexibility on that. Integrated resource planning is key on that.

Last point I would note is that, you know there are these other elements, too, of this effective management of this system that I think we need to take a look at so that in the interest of the cooperative federal and state approach here that we are really advancing, you know, the most affordable and effective grid and power system we can.

MR. WISE: To answer to the first question is yes. We really like the states, as I mentioned in my comments, Texas, we think really got it right. We think the states do have a real good view. And they spend a lot of time on it. So I think that is really good.

The second question you asked, really, we could spend a whole lot of time talking, thinking about, but let me and try and inject a different flavor to this a bit. You know, long-term contracts basically have time-value risk. Huge time-value risk. And as you get further and further out, that risk becomes even greater and more substantial and what some of the QFs want to do is basically transfer all of that risk, all of that time risk to the consumers, and being a consumer advocate as we are, we don't think that's really fair. We don't really like that concept at all.

It removes or reduces the flexibility that we have as resource planners, or be able to provide for our consumers at the lowest possible cost over all ranges of time. And to give you an example of that, our load forecast dropped from about 3% growth to almost nil over the last two years with what's going on inside of the SPP and inside of our area.

And with that in mind, we had a PPA that we could get out of, and we cancelled it two years early and saved our consumers 17 million dollars, that they would've otherwise had to pay if they'd been locked into a long-term contract.

So removing this flexibility from us as resource planners or those of us who have to provide for our members that, you know, could really substantially take tools out of our toolbox. In addition, and you remember -- and you were there two months ago in your home state of New Mexico and you were at the SPP board -- and we approved some substantial changes to the SPP market, and one of those was because we built 10 billion dollars of transmission that we largely have this pool now.

And we determined that we could reduce the reserve margins, but also we determined that we didn't have to have firm transmission for our planning reserves. That is an incredible flexible option now for our load-serving entities in the SPP, so I don't have to contract and go get firm transmission for resources well into the future. It's a one-year look ahead.

So I've gotten out flexibility for 12% of my load, which is my case is 180 megawatts, that I have the flexibility to go and contract with anybody that's in the pool and has qualified capacity. So these are flexible options that consumers are really reaping benefits for right now. Largely because of, you know, your leadership in developing the RTOs allowed this to develop. And it will continue to develop as the markets and competitive pressures continue to form.

MS. WHITTLE: Okay, where to start? We, as I noted before, are very small hydroelectric projects that were built in the 1990s, the vast majority of which are 5 megawatts or less. They are not manned 24 hours a day, and they do not, under any circumstances, have direct access to ISO New England market.

So when we're looking today at receiving a real-time L&P price that is sometimes negative, our folks, and we are not manned 24 hours a day, it takes the full rest of the day to maybe make up for the losses in having to pay to generate power.

Now, that's the issue that we face with the real-time L&P, as a proxy for avoided costs, but on a foundational level, the real-time L&P is not a proxy for an avoided cost rate. What we're supposed to be looking to today as an avoided cost rate and I'm speaking in an RTO market because I think, you know, there are many ways to calculate it in the non-RTO markets, the unorganized markets.

Is that -- we're looking to what the utility is buying. The utility has a number of means to procure its energy in the market. If it purchases only in the R2 market, it's purchasing least and probably more than 95% of its power in the Day Ahead market. It has contracts, it may still own its own generation and it has a long-term look that we believe must be considered when calculating an avoided cost rate, even in an RTO market and especially when these small resources cannot reach the RTO market.

What we're essentially doing is providing power to the utility, not to a market. So I think the FERC, to answer the direct question, the FERC should provide some guidance and I think put an end to that use, in particular in ISO New England, and provide guidance as to what would consistent an avoided cost rate in an RTO market, because it is very different.

Some of the same data may be available. It's specified in the regulations, but I'm not sure that data is as relevant today in RTO markets, especially with divested generation as it is in markets where there's no RTO.

MR. SIPE: I apologize if this is taking two bites of the apple, but I promise to say something different than I did the first time. First, I thought Mr. Burleson's description of how Southern does its planning sounds exactly correct to me. That those numbers are used for internal planning, as well as external planning. And I think that's the appropriate, you know, you use those terms across the board.

By contrast, it sounds like Idaho doesn't do that. We heard a very different way that they qualify utility investments and the way that they're doing avoided costs apparently, and that may be part of the problem in that state is that they've got different ways of doing it for the two resources that don't match up in some way, that maybe if there was a better match between those types of prices and planning, that that would answer some of the problem. I don't know.

But when we talk about the, you know, the long-term risks, certainly if you sign a long-term IPP, because you're thinking that you want to be able to avoid the energy costs, you still have the risk of stranding that IPP contract when you're not using the energy. I mean you signed up, expecting to get a certain amount of energy value out of it, you've lost part of the value proposition.

I think the, you know, trying to analyze what the risk is in losing that value proposition as opposed to paying a fixed price QF, and again, I think we've got to find some way to get longer term energy prices right if we really think they're declining and we're sure of it, then we should use that assumption.

But this is where I think you run into the encouragement question. Now, Congress may have been wrong in telling you that they wanted you to encourage these resources. But if you truly find out that one way of calculating avoided costs, or one contract length really makes it so these guys cannot finance a project.

I think you seriously need to take that into account when you look at how much risk, or how to evaluate the risk. So there is a risk in any fixed term contract, maybe avoided cost ought to in some way reflect that, what you call the carrying risk, I think. But those are questions about trying to get the avoided cost right.

You still have the obligation. Until Congress says that they were wrong about wanting to encourage this, based on avoided costs, to have a financeable way for these QFs to move forward, and it's got to be fair to rate-payers and avoided cost should be fair, so do everything you can to get that right.

But once you get to the point where you're not offering a contract that can finance them, then I think the Commission needs to step in and say, "Wait a minute. That's probably not a way we can do avoided cost."

COMMISSIONER KAVULLA: I would just say in direct response to your question, Mr. Chairman, that I think the guidance that's already been offered on this subject of avoided cost methodology is largely sufficient. And attempts by FERC to further introduce administrative making of this process would really be quite difficult because of the differences between the various regions in generator revenue models.

I mean you sat through for the past couple of days hearing about the wide variety of differences in electric transmission planning and I know just from having dealt with a single regions or the one thousand compliance filings and interregional compliance filings, that that was a morass of regulatory activity that you are probably glad to have, sort of, more or less, in the rearview mirror. You know, take that and multiply it by two or three, and that would be the amount of regulatory transaction that would have to attend any thoroughgoing intervention into it with the cost methodologies.

I'd also just say this, that we should be aware that we don't allow the tail to wag the dog here, because the discussion you're hearing at this table has more to do with larger debates about how generators earn revenues in the market, whether they earn revenues strictly from a centrally clearing market on a real-time or if they had an energy basis, if there's a capacity component, if there's an ancillary service component, whether you allow out-of-market hedges or long-term contracts to be layered over that, or whether in the states, like in the Western interconnection, you simply allow vertically integrated utilities to do cost or service rate-making.

I think you should let, if you offer any guidance, it should be that for PURPA projects fall out of that tree, which is really a larger public policy determination about the nature of generation and how it's compensated. But you shouldn't allow, frankly, this sideshow which has become a footnote over the course of time because there's far more, frankly, influential ways to introduce renewable energy and competition to markets, to somehow supersede the much more important debate you've been having about the electric markets and how resources are procured.

MR. BURLESON: Yes. Thank you. I just wanted to clarify in response to my earlier response to your question, Mr. Chairman. And also to add to that. So I think, when I think about the long-term projections, and I think there is clearly a role for the Commission to think about making changes in that regard, in terms of that requirement.

When the utility has owned generating capacity that is under development typically in our four states, there are requirements during the construction process that the utility continually go back to the State Commission to update the economics of continuing those projects to ensure that they're still cost-effective for customers.

And in fact, typically we are required to do that about every six months or so. If a project is not, it can be cancelled during the development of the project, and in fact, we've got a history on our system of cancelling nuclear projects that were under development, cancelling coal projects that were under development, simply because they were not cost-effective for customers to continue with.

We also have the ability -- once an owned unit is up and operating, the ability to retire that unit before its projected service-life expires. You just don't have those kinds of opportunities with long-term fixed contracts. Your customers are obligated to 100% of the cost of those contracts. And 100% of that cost is fixed, if it's based on a projected avoided cost.

So that's really the distinction there and it really puts customers at a disadvantage in terms of the amount of risk that they ultimately have to carry. And I think, you know, a way of addressing that would be, perhaps the Commission could consider fixing a portion of those costs based on a long-term projection, and letting the other portion of them in the QF contracts be variable.

So, in other words, you would set a floor and as an example, I'll just throw a number out. Set a floor that's 50% of the long-term projection of avoided cost, that the QF would get paid actual hourly avoided cost, but there would not be an hour in which the actual avoided cost payment would be less than 50% of what the long-term projection was.

It still doesn't take away all the risks, but it certainly would mitigate a large part of the risks that our customers bear when we have to lock in long-term projections at the full avoided cost. SO I just wanted to clarify and add to that.

COMMISSIONER RAPER: I will be brief. I just -- in response to Mr. Sipe's comment regarding whether Idaho does it right and whether we should have one rate, perhaps he's correct. Perhaps we should look at a single rate. I can tell you that the reason that our standard rate is different than our IRP-based rate for larger projects is because Idaho, as a state, has promoted renewables.

We wanted the small guys in. We've got a ton of hydro, we've got biomass, we've got geothermal and we truly wanted to promote those small renewables in our state, consistent with PURPA and its intent and the heart of the law. So the standard rate is based on a combined cycle gas plant.

That generates a higher avoided cost calculation than the IRP rate does, which is why we have the larger generators trying to come in within that standard rate. So, to Mr. Sipe's point, perhaps the way to avoid that gaming in our state is to go with the single rate. It would be truly unfortunate, because we really do believe that those standard rates that we have promote the intent and purpose that PURPA originally intended.

MR. ROSE: Ms. Whittle brought up something in her response that's come up in Michigan as well, so I feel compelled to say something about it. I think Laura Chapelle, this morning, described who belongs to the IPPC, their basically small hydro, mostly small hydro and some relatively small biomass producers. The utilities there, as well, are arguing that their avoided cost or incremental cost is essentially the market price that they get in the RTO market.

The problem with that argument is that, at best, maybe you're looking at a marginal cost, a short-run marginal cost, but that's not really the same thing as the incremental system cost that we generally use in order to calculate the avoided cost. So, that's a, maybe a clarification that the Commission might consider that the short run is not going to really reflect that avoided cost that I think, what Congress had in mind, when they wrote PURPA, or that's in the FERC rules today.

Because there'd be tendency, especially now with relatively low prices, there's a, I think, a temptation to try to use that as a shorthand way of getting out of avoided cost, but it doesn't really reflect that, certainly not the utilities' avoided cost.

MR. HUGHES: I'm just going to run with what Ken just said. Where this discussion is drifting is, we're trying to create a huge and very important industry, power sector in this country, where we don't have any long-term contracts. Okay? They're too risky, so everything's got to be done on spec. I mean, is that where we want to go?

I mean, already the organized market provides little in the way of long-term certainty of anything that will fund, you know, a base-load plant. And now we're trying to do the same thing in the unorganized markets with some of the best technology that this country's ever come up with. I think this is a very serious discussion that needs some kind of resolution.

MR. BROGAN: Mr. Chairman, I'd like to step back to the very beginning of your question and take a look at, also at the Congressional directive. Congress directed FERC to adopt rules, which then the State Commissions and utilities have to implement.

With that paradigm, I think the Commission does have a very important role to provide both guidance and to keep its rules updated to reflect changes that have happened since they were first adopted in 1980.

Secondly, as I look around the room and around the building and it pains me as a former State Commission employee to say this. I see a lot more expertise in this building than I would see -- I'll pick on Pierre, South Dakota, since Commission Kavulla is here --

And I think that both the utilities and the commissions really respect the fact that you deferred these decisions and actual calculations and determinations of avoided cost to the State regulatory body, but what also appreciate and what we're saying we need is more guidance as to how factor in all of the things that you have in your 304(e) rules. And I think that can come from you far better than from anybody else.

MS. WHITTLE: I just wanted to add one more thing about the long-term contract issue. Setting aside the avoided cost rate, assuming it will be fixed in New England, hydroelectric projects, especially some of our members, have licenses that span thirty, forty, fifty years and then they're renewed.

And some of these licenses will be coming up for renewal in the next decade. Obtaining a new hydroelectric license is very expensive. Agencies are requiring more and more of licensees and requiring stricter operating requirements to protect aquatic and fish and wildlife.

So from our perspective, having a long-term contract can provide a lot of benefits, in that when we're in re-licensing, we understand, you know, the revenues that will be coming and can make determinations on the re-licensing.

And I can't tell how beneficial these projects have been to the country and the New England region. They provide benefits that are not always obvious in that they're in remote locations, so they support load in remote locations, and they're very reliable and have long operating histories and lots of data.

And so, you know, we're at a crossroads here, but we really need some kind of guidance on this issue, and we really do need some long ability that have some long-term certainty that we'll keep developing these projects and keep running these projects and obtaining new licenses and running them for another thirty or forty or fifty years. Thank you.

MR. FOLEY: Just a couple of quick points. I think the original tentative purpose still holds true here and is very important. And that's access to the market competition and diversification of resources, all with an objective, of course, of making sure that we have the lowest cost affordable power going forward, but achieving some very important other kinds of objectives.

This notion of, what we're also trying to do by, you know, through long-term contracting, is -- , you know, private sector capital investment, you know, in this kind of infrastructure that we all, the public, benefit from. So there's a big issue about, you know, whether, you know, the question of the sanctity of long-term contracts. Those really are going to be critical if we want private capital to step in and developers to develop these kinds of projects.

I think, without that, you just won't get there. There is one factor that is emerging, I think in our power markets, and just something to put on the table. We're seeing increasing interest of a large corporate third party interest in purchasing renewable energy power. But in some places, that third party purchase is not available.

And so we do see an opportunity for some offtake for some of these larger renewable energy projects with third party contractors, including the larger companies. That may afford some flexibility as we look at this going forward. But the key thing is that the long-term sanctity of contracts and we've got to be very careful about that. And they are the key to getting projects financed and built.

COMMISSIONER LAFLEUR: Well, my goodness. I started off the day by saying I had worked on early PURPA contracts. Thank you, Ms. Whittle, for saying that Massachusetts was a leader. In spite of those thirty years, it seems like the more I hear about this, like many things, the less I think I understand it.

So I want to ask one broad question and one very narrow question. And the broad question, for those of you, unlike Travis who thinks we should do something, as you answer this next question or any question, I would be interested in whether you think we should re-open the regulations and take a real look at them, offer some sort of guidance -- somebody mentioned a Policy Statement -- or just be more vigorous in our backstop and not just keep issuing Notices of Intent not to Sue.

I mean the one time we did bring a suit, I ended up voting to bring it and settling it, but it -- so if you want us to do more, I'm interested as you answer and how. But substantively, I would like to dive back into this issue of the length of price assurances, because we heard, I realize to Travis' point there's very different market structures, but we heard two such different things from Commissioner Raper saying that she didn't feel the regs gave her any flexibility to reset avoided costs so the only way to upset that was to have short contracts to what I know to be the case in New England and other markets, avoided cost changing every five minutes.

Those bookends seem too wide to me. And I'm trying to gauge what's baked into the statute and what we can really change, but for people who think there should be some -- we talked earlier this morning about that, you modulate amounts by -- as you get deeper in your dispatch stack, avoided costs might change. Well, that's not going to happen if you do it every thirty years.

So for those of you who think there should be any kind of reset or whatever, how often do you think that should be? Are we talking every five years, you reopen a piece of it? Or you set avoided costs for a period? What would you think would be reasonable and within the statute? It'd be somewhere between no reopener and every five minutes, there's got to be something a little more modulated.

MS. WHITTLE: Thank you. I'll start. First, I do think that there is some guidance that is needed with respect to what can constitute an avoided cost rate in an RTO market. And I've expressed our strong opinions on that issue and I won't repeat them again.

I think there are many ways you can do it that is both fair and accurate and represents an avoided cost to the utility in an RTO state, whether you have divested or undivested.

I will say, with respect to a Policy Statement, the geek lawyer in me would rather see a Notice of Proposed Policy Statement come out first, so that we could then respond in writing and have a more deliberative process with, you know, all the stakeholders, you know, who didn't come here today, participating.

COMMISSIONER LAFLEUR: -- versus a rule-making or something, not that we'd jump right in --

MS. WHITTLE: Yeah, no, so I don't think the rules, I don't think the regulations need to be changed. In fact, I even brought Order 69 with me and read it last night while I was watching the Olympic swimming trials, and I actually think it's a pretty amazing document, considering how old it is.

However, we do think there is some guidance to catch up in the RTO markets in particular, and to the extent you think there's any modification to the long-term nature of a contract. I suppose that could be brought up in a Notice of Proposed Policy Statement as well. But I don't see, having just read Order 69, any real changes that are needed.

MR. WISE: Commissioner, I'll just quickly discuss your second question. The first one answer, I don't think you need changes. I want to make sure we differentiate between energy and capacity, because energy is on a five-minute basis and settled five minutes in the RTO markets. Then you have the Day Ahead market too, so you can hedge a little bit that way.

But in terms of contracts, what I was discussing before was actually in the capacity piece. And since we have a one year look ahead now in the SPP, actually the SPP transmission planning process was studied afresh every year and looked forward for two years.

Currently right now, their studies show that all 750 generators in the SPP, all 750, have a percentage of deliverability to all of the load in the footprint over the next two years. So one to two years could be reasonable for the consumers in the Southwest Power Pool with regard to our new rules that we'll be filing.

COMMISSIONER LAFLEUR: What's the contract length? For price, you mean? Is that what you're saying? For capacity price?

MR. WISE: That would be the contract or the capacity price. If you want to reset it, the problem is, again, because of the nature of our load forecast and the need for it, or the lack of the need, it's going to change from year to year. You know, with long-term contracts.

COMMISSIONER LAFLEUR: PURPA's obligations unnegotiable? I mean you don't go through need with PURPA, right? You have to buy it. We're talking about what you pay for it, so would you reset that every year?

MR. WISE: First of all, I would consider how much you need to buy and try to maintain as much flexibility as possible, looking at the resource planning need for the consumers. If we bought everything we thought we had forecast for out in the future, plus the reserve margin, and as I said, the low forecast drops substantially you're way over and your consumers are paying exorbitant amounts of money for energy they don't, or capacity never used, or never can use. Right?

So you remove that flexibility the longer you go out. So what we look at is actually planning long-term for just our forecasted load or maybe a little bit less than the forecasted load. The reserve margin piece is the one that I would like to be able to say, you know, and the SPP has taken care of our needs in terms of having the correct capacity one or two years out and look at.

COMMISSIONER LAFLEUR: Don't you have to buy the QFs and other things come up and down. I mean I didn't think you got to say, "Oh, this year we need load, so we'll buy it. Next year we don't need load, so we won't buy it." I thought that was baked into the statute, buying it. We're talking about how much you pay, I thought. Don?

MR. SIPE: First, I agree with your last comment. I think need should be baked into the avoided cost. I mean your avoided cost should reflect the need and, you know, the need may be very low. Maybe you don't need any capacity at all. Maybe the capacity price is zero. I don't think that's inappropriate in a case where the utility itself is saying, "We're not building, we're not buying," so I think you're right. I don't think you handle that on the obligation side.

You handle it by getting avoided cost right. In answer to your first, sort of general question, I don't think the rules need to be changed. I think that the state that we're at, we need more vigorous Commission enforcement of things like standby and backup rates. And I know it's more work and it's case-by-case specific, but there really is not a general principled way that everybody's going to predict the future the same way.

I just think trying to do that, or say, this is not allowed. You want people to be looking at the way they plan, what they think their system needs and setting their avoided costs based on their best judgment. And I think the Commission's backstop role is important in making sure that you are encouraging QFs.

In terms of how long those contracts need to be, I think until Congress changes its mind, they've got to be long enough that a QF is financeable. And they have to --

COMMISSIONER LAFLEUR: -- price for that whole time?

MR. SIPE: No. They've got to be long enough that it's financeable. Now, I've heard someone say earlier this morning, for instance, that well, you give us fifteen years instead of twenty and then you put me on the market after that, I could do that.

I heard a suggestion from Mr. Burleson about how you could use the avoided cost -- this is why I think the Commission judgment is important as a backstop. Some of these things are obviously going to be done as a way of not having these things built and not allowing them to compete.

And other things are going to be a reasonable reflection of what the utility really thinks its risk is, and how to value that risk. And I don't think there's a general rule for that you can come up with. And I think Commission opening a rule-making to try to set a general rule for that, you know, that discussion could go on for a long time now. As an attorney, maybe I like that. But I wouldn't think, for your docket, it'd be particularly helpful.

COMMISSIONER LAFLEUR: -- so my colleagues have a chance. Who do I see up? Kris? I couldn't tell whether Kris or Kristine was your friend, so I want to be whichever one is your friend.

COMMISSIONER RAPER: You got it right. Well, and you provided me the greatest gift that I've ever had on Christmas Eve, because of course, the Idaho Commission was on the other side of that docket and, while I wasn't a Commissioner at the time, I was counsel for the Commission and that was my greatest Christmas Eve gift ever, so thank you.

And I may be on the wrong side of this argument, as far as how you posed it and asked it, but I wanted to be clear about the comments that I had made and how you were talking about avoided costs moving all the time. I would think avoided costs does move all the time, but it's the Idaho Commission's interpretation of FERC regulations that a QF has the option to choose to be priced at the time that they enter into the contract, or at the time the energy is delivered.

And it's been our interpretation of FERC regulations that if they choose pricing at the time they enter into the contract, that that's the price that remains for the duration of the contract. So again, as I said earlier, if there's a different proposition that FERC wants to put forward that would allow a different interpretation of that regulation, we're all for it in Idaho.

And as far as at what point should a contract be re-opened, you know, we picked two years, and as I said, everything else functionally within those contracts is exactly the same as it would be in a twenty-year contract. They're still entitled and onboard for capacity. They're part of the resource stack. Everything remains the same.

We randomly pick two years because it goes with the IRP cycle of our utilities and because otherwise we have no knowledge or understanding of what the dollars are that are spent or needed to make a QF financeable. Now, if at a given point a QF wants to turn over their books to us and show us that they're financeable at a given point, I'm all for that.

I would look at that and I would consider that. Because I do believe that -- well, I don't believe that PURPA or FERC regulations require us to give a contract length that makes a QF financeable, but I do believe that the intent of the law is that these renewable resources be allowed to come on board.

So I challenge a QF, I mean, you know, look at our history. We've got dozens and dozens of contracts that come before us. And along the way, as we've changed our methodology and the way that things are calculated, for the last ten years that I've been at the Commission, each time we make a modification to the methodologies, the QF says, "We won't be financeable. You can't do that."

And then we change it. And then more come on board. So, again, tell me what it is that makes a QF financeable. Show me the books, show me what you need in order to get there, and then that can be weighed within the proposition and within the allocation of costs and choosing an avoided cost for the QF resource.

COMMISSIONER KAVULLA: Yeah, I think it should, of course, be pointed out that when PURPA became law and when the Commission adopted its implementing regulations, the business model of all of these utilities was uniform across the country. I mean, all of them self-built, some of them long-term contracted generation. And those things went into rate-base, utility-owned generation.

And the avoided cost was meant to be a mirror reflection of that long-term revenue model that promoted entry through these monopoly enterprises. And now, as you've had a diversification of business models, I do think it's at least reasonable to think what FERC might do if it's not already being done to continue to make sure that avoided cost methodologies are actually mirroring the over-arching business model for generation in a particular marketplace.

But let's say hypothetically -- and FERC has reasoned in many of its orders regarding Eastern RTOs that the idea behind the market design of those RTOs is to allow a completely private generator to earn sufficient revenues from its Day Ahead energy, real-time energy capacity and ancillary services market to enter and compete and continue to operate.

Whether or not that's true is frankly a much larger question than this. But in that market, if that's your underlying premise of generator revenue, then it would seem appropriate in that context for PURPA's avoided cost, to simply be a reflection of that methodology. In other words, perhaps a long-term contract where the off-taker has some kind of bidding obligation or transaction obligation to enter the QF's output into a market, but where the contract is settled through the clearing prices of that given market.

Again, in a hypothetical where that load-serving entity has no other long-term contracts and is a default supplier, which is simply a price-taker off of the market, whoever its remaining consumers are. But in the situation where you have an unrestructured utility, which still does long-term resource planning and avails itself of the monopoly protections of many states in the Western interconnection and some others, it would seem appropriate to countenance the idea that QF should generally get the same deal.

So thus, my recommendations on Page 9, that if you wanted to adopt something that didn't have a lot of compliance filings associated with it, you could at least try to take other measures of competition in these markets as a proxy for allowing some of the EEI language to be adopted, so long as there were real safeguards that competition had made it into the market.

You know, otherwise, I think it's reasonable for the Commission to ask, trying to put the shoe on the other foot as a test. I mean if EEI, for instance, is proposing language that energy be compensated avoided cost based on the index price on the bilateral market at the time of delivery, or that shorter term contracts be proposed, then you should also probably ask, "Well, why doesn't rate-based treatment end after two or five or seven years and then, you know, utility-owned projects get revalued, tagged to whatever fair market value they have on the market?"

That's not the business model of generators in those places and so it follows that it probably shouldn't be what you do with regard to PURPA. But these are things that, you know, Commissioner Raper and I and my colleagues can debate on our own, and I think there is still a lot of work to be done within the context of those laboratories of democracies to figure all of this out. Thank you.

MR. HUGHES: I don't think we need to, or do I want to see the regulations opened up for review. I think they were ingeniously written in the context of the day, when they were written, which was when they were -- you know, the wreck of 200 nuclear power plants all over the country that had to be abandoned. And so one concern about reviving the regulations would be that it would allow the, you know, some states to basically abandon their responsibilities under the law if too much flexibility was given there.

Even the best of regulations is probably not workable 100% of the time and so I think, and I would hope that the federal power act in PURPA give you enough authority to deal with these one-offs on a case-by-case basis, which would probably, you know, be clearly the best solution right now.

With respect to re-opening these contracts every two years, I'm not aware of any, you know, rate-based that gets re-opened every two years. And where there's a reconsideration of whether or not they both still belong in the rate-base and I'm fully aware of how power plants get reviewed during the course of construction. But once you're in rate-based, rate-payers are pretty much locked into those.

MR. BURLESON: Commissioner, I was going to address your second question first, length of price assurances and just give you some data from our experience. We now have almost ten times the number of long-term contracts with renewable generators than what we have QF contracts. So these are not QF avoided cost contracts.

And the reason we've got almost ten times the number of those, as compared to the QF contracts, is because we're willing to give longer terms, longer contract terms generally speaking, with a locked-in fixed energy price, but that locked-in fixed energy price is typically, let's call it 50 to 60% of the long-term projected avoided cost.

So we're willing to take as a utility, on behalf of customers, a longer term length if we set those prices well below the projections of avoided cost. It helps to mitigate the risk. And apparently developers prefer that approach. So we see that very evident, in terms of the number of contracts that we've entered into.

And I think that's a --

COMMISSIONER LAFLEUR: Did you say that, the term of your PURPA contracts?

MR. BURLESON: We have different term lengths, typically those are ten years. We do have a few where twenty years are options, but the timing of those -- to get a twenty-year contract, it has to be in conjunction with an RFP for traditional capacity, and we don't do those every year, only when there's a firm capacity need.

And so we see the developers entering into these contracts at much less than our long-term projections of avoided cost. So we know that the projects are economic. If we were to extend our contract lengths for the QF contracts and pay full avoided cost, there would be huge economic windfalls to those renewable developers.

And so I think that transitions me back to your first question. Do you need to re-open the regulations, clarify -- and I think, yes, either you need to clarify what is intended by paying the avoided cost calculated at the time the obligation is incurred, because many have interpreted that to mean that that is the then long-term projection of avoided cost.

And what's that resulting in is typically shorter contract term lengths. And so if that's not the intent, that in fact those avoided costs could be periodically adjusted, even during the term of the contract. I think that would be a good clarification. Otherwise, I think there may need to be a re-opening of that particular regulation. Because it's clear to us that the developers value the longer term lengths, rather than the shorter term lengths. And we, on behalf of our customers, only want to enter into those very long term length contracts if it's well below our projections of avoided cost.

MR. BROGAN: I think two quick points. On EEI's membership, which represents 70% of the electric industry, went through a whole series of calls, and as you can imagine, utilities don't agree.

COMMISSIONER LAFLEUR: Those calls -- I don't want to be on them ever again.

MR. BROGAN: But in our pre-filed statements, both of Mr. Schmidt and of myself, we provided some fairly narrow and specific suggestions for revisions to 204, 304 and 309. We think that those provide a framework for reopening and discussing modifications to those particular rules and we think that would be appropriate.

I must respond to a couple of comments that were recently made about once something's in rate-base, customers are locked into it forever. One, they're not locked into it forever for various reasons, but more importantly we often see the return on equity that is allowed for that rate-base amount, to vary every time there's a rate case, which may be every two years, maybe every three years or for some utilities I've never been involved with, maybe every twenty years.

COMMISSIONER LAFLEUR: -- once, unless anyone has anything burning, I guess, Liz, I'll give you the last word. But I want to give my colleagues a minute.

MS. WHITTLE: I just wanted to make one clarification and that is that avoided cost is based on the utilities' avoided cost. And so when there's all discussion about what generators are offering and what generators' marginal prices are, what generators are providing in RTO markets -- even assuming that my folks could reach an RTO market, that's not the benchmark for an avoided cost rate. The avoided cost rate looks at the utilities' avoided cost. And what we're saying here is that the utilities' avoided cost is the default energy rate or what the utility buys its power.

It could be in the real-time market, plus contracts plus renewables plus whatever. And it's that that we're looking at in determining avoided costs, not the cost of an individual generator and that's in the statute, in the conference report, in Order 69, and it's pretty much clear throughout. Thank you for letting me make that clarification.

COMMISSIONER LAFLEUR: That it is Ken, right?

MR. ROSE: Just very quickly. Let me urge you to not get too caught up right now in the current market conditions, because I think that's what a lot of the comments are obviously directed at. That can change obviously very quickly. I'm not an attorney, but I think a very clever attorney could write a contract that is worthwhile to both parties, or agreeable to both parties, that takes into account changes in the market condition.

Right now it's been pointed out by the Chairman, you know, prices are low, I think there's a lot of concern right now that they don't want to commit to a long-term contract, but when I hear somebody say, "Well, right now, they want long-term," that's because they think the price is going to stay low. They'll want short-term if the prices start going up.

And I don't know if that will happen. I'm not good at forecasting, but you know, the market conditions can change very quickly, so any kind of a change that you're -- I don't believe there's a serious change to the rule that's necessary, but any change that would be made has to account for all market conditions, not just what's going on today.

COMMISSIONER LAFLEUR: I just want to ask a real quick question. Both this morning and in this panel, several references were made to foreign investors or foreign companies coming in. And of course we're seeing more of that across the industry. Does anyone think that that makes a difference under PURPA? What the -- or was that just kind of atmospheric? I mean, is this --

COMMISSIONER RAPER: Well, no I was just -- because it was my reference to Italy. To me it's anecdotal, but it's also a statement of who's making money and lining their pockets on the backs of rate-payers? Or to the rate-payer's detriment? If everything else is fair and just and reasonable, then we're good. I don't care who it is that's -- you know, investing and creating the projects.

MR. SIPE: The same -- if everything else is fair, we don't care.

MR. FOLEY: And I would just reinforce that point and note that, you know, these are global industries, of course. Utility industry's global, global players in renewable, very much of a global industry as well. And U.S. and the international companies are part of this great expansion, what's happening in renewables here in the U.S. and around the world.

COMMISSIONER HONORABLE: All right. We've reached the 3:00 hour, which for me is an afternoon lull. So this question requires audience participation. Raise your hand -- now some of your neighbors are maybe napping. Raise your hand if you've been here all three days. Okay. Give yourselves a round of applause. That's to wake up your neighbor. Really.

And on a serious note, we -- I'm not sure if we really knew what we were doing when we planned all these Technical Conferences, but it's invigorating, it's exciting and this is yet another topic in which, as you can tell from the participants, there's a great amount of interest. And I want to thank those of you who've participated this morning, this afternoon, who have submitted written comments. It's very, very helpful to us.

With regard to PURPA, since I've been here at the Commission, I've heard a bit of everything, honestly. I've heard it's working well, I've heard it's horribly broken, we've even heard from the Hill as you're aware, from members of Congress who have constituents that have raised concerns to them about PURPA and its implementation.

I've heard it's either costing consumers enormous amounts of money or it's leaving rate-payer savings on the table. But especially with regard to cogen and CHP, I find, and I admit, it harkens back to my days as a state regulator, that there's a tremendous opportunity for greater energy efficiency, economic growth and ways in which we can support America's manufacturing sector, for the most part, Commissioner Raper, with efficiency and becoming more competitive, which is important nationwide.

I certainly believe we can all agree that the grid has undergone tremendous change since PURPA's enactment. We've heard a bit of that today. We certainly, today, have more robust wholesale electricity markets open access transmission, what will or may or may not be the clean inner -- of a clean power plan, renewable portfolio standards and certainly most of these or all of these did not exist in 1978.

So we've come a long way and we're at a place at a juncture where we are attempting to wed, or at least coordinate what is happening today with the original intent of PURPA, as Congress sought then. Today I certainly appreciate hearing from you what is working well, more importantly what's not and from my new perspective, newer perspective, what we at FERC should or can do to aid in the successful implementation of PURPA as Congress set forth.

And certainly as a former State regulator, I've had the benefit of some perspective in making avoided cost determinations and I'm looking forward to working with you in this capacity, now having been through, I've sat in the seat that the State Commissioners sit in and interacting with FERC. Kris, I, too, got a Christmas Eve call, I was saying to the side here, and it made my day too. I don't know if it was my best Christmas gift, but it was a great one.

I'd also like to thank all of you, most of all for your work in implementing this. I think this panel, in particular, demonstrates that it is not a simple task, so I'll get to some pointed questions and I appreciate Commissioner Clark for letting me jump ahead in the queue.

So, John Hughes, I love engaging with you. You're never bashful. You said that you had some asks and one of the asks for the Commission was that we should acknowledge that implementation is flawed and something that I didn't get. But I want to ask you why? What purpose would that serve? So I'm with you on the other two, should the -- I mean understand your ask. The Commission should issue a Policy Statement to promote cogen, direct staff to prepare guidance, that would be helpful, along with best practices.

What was your third point and what was the impetus for it?

MR. HUGHES: The third point was an ISO or RTO tariff that -- the word tariff may be somewhat of a misnomer in reality, it'd be much more in the form of guidance with binding guidance, that people at a manufacturing plant who are responsible for selling power and they may typically be a chemical engineer, and not a, you know, the type of technical wonk that's more familiar the way the organized markets have been structured and their history.

COMMISSIONER HONORABLE: I appreciate that and I certainly heard that from IP and others in Arkansas, you know, skilled plan operators and the like. That's right.

MR. HUGHES: It could serve several very useful purposes. One it would be a user friendly interface between the customer load that has the behind the meter generator and the organized market. It also would provide the organized market a requirement, at least somebody on their staff understands what a QF is, what a cogeneration unit is, what standby rates are for, why they're essential.

And the general historical legacy of why PURPA is here and why NIPPC is here. We're finding that that technical expertise is not very common in the industry and especially as the baby boomers like myself begin to retire and they're replaced by people, younger generation that don't even know what PURPA is, or for that matter, CHP or cogeneration. So that's the intent of that.

COMMISSIONER HONORABLE: Understood. Thank you. I hope you aren't retiring anytime soon. I don't think Charlie is going to let that happen.

MR. HUGHES: Well, I got -- this tie is new, so I want to get some mileage out of it before I retire.

COMMISSIONER HONORABLE: Good. Good, good, good. My next question is for Ms. Whittle because you had some asks as well, and you were trying to get it in. I understood that you believe that the Commission should update the avoided cost definition to say that L&P is not the best way to calculate it. What were your other asks?

MS. WHITTLE: Yes, what we suggest is that the Commission should issue, first, a Notice of Proposed Policy Statement and then a Policy Statement. The geek lawyer in me, again.

COMMISSIONER HONORABLE: Well, and I appreciate that. You guys want the opportunity to have a say.

MS. WHITTLE: Yes. Policy statements are interesting for, you know, a few purposes. And we would like the Commission to confirm how avoided costs are calculated in L&P markets and confirm that you look to the utilities of what it costs, and that utilities' avoided cost is not a real-time L&P. It's more like the energy price that they pay to serve their load, that they procure from the market from whatever source.

We would also like to reaffirm the right of the QF to enter into a long-term power purchase agreement at an avoided cost rate, established at the time a legally enforceable obligation is incurred. We do not -- I don't have authority to give a length of contract term. So I can't say whether it's five years, ten years or twenty years. Certainly more than one.

And more vigorously enforce PURPA. I think what we have found, through the years, especially with these small hydro-developers, is that it's very expensive to take these battles to the State Commissions, to the Courts, even to the Commission, and when we come for help, we really need help. And generally speaking, these folks don't come to FERC as their first choice. They really do try to work things out at the state level and through their processes and through the people that they deal with all the time.

So when we come to FERC, we really need the help and it seems to be an efficient way to get some history and some precedent out there to make future cases a little bit easier.

COMISSIONER HONORABLE: Thank you for repeating those, because I didn't find them in your comments, and I greatly appreciate the challenge that QFs face in all of the regulatory hurdles, whether it is at the state level or whether it's here. It can be costly. It can be protracted. And I can also say as a regulator, I've seen an evolution in the way in which FERC has handled these, and certainly Commission LaFleur, then Chair LaFleur, aided in attempting to smooth that out, on behalf of my --

COMMISSIONER LAFLEUR: -- getting into it too, so --

COMMISSIONER HONORABLE: Well, you did, you did. I was trying to do half glass-full there, but thank you for rounding it out. So it is an evolution and this process allows us another opportunity to try to get it right. I don't think we should allow PURPA to be the enemy of good, but this is an opportunity for us to maybe attempt to provide some consistency while appreciating the diversity of the states. So, thank you.

COMMISSIONER CLARK: Thanks, and thanks everyone for being here. With all this talk about Christmas gifts, I'm feeling a little left out, so I just -- Kris, I just want you to know that I feel like I gave my Christmas gift early when I dissented from the original order of suing the State of Idaho.

COMMISSIONER RAPER: Thank you for that.

COMMISSIONER CLARK: Thank you. And to all my colleagues, present and past, I kid because I love. I think most of my questions have been asked and answered, but I did want to give everyone an opportunity to focus specifically in on couple of the nuances that I think NARUC has proposed, or at least I interpreted it as being -- Travis, you speaking on behalf of NARUC, the comments that you filed, which was --

COMMISSIONER KAVULLA: Purporting a twenty-year-old resolution of the association.

COMMISSIONER LAFLEUR: I thought he was speaking ex-Cathedra.

COMMISSIONER KAVULLA: I don't have the hat.

COMMISSIONER HONORABLE: That's a very good question.

COMMISSIONER KAVULLA: So, and it's this idea that if the Commission decides that there is some level of clarity that needs to be brought with regard to length of contract terms and avoided cost rate and what needs to be paid over the course of a term and how locked-in it is, and all of those things.

So if that threshold is met, that as I understand, what NARUC has proposed is that, if there needs to be that clarity, then there may be certain circumstances which the Commission should take into consideration that would allow for that potential relaxation of those rules.

And I'm wondering if others wish to comment on that specifically? What NARUC has proposed, does it make some level of sense if we go down that route to bound it in some way by taking into consideration things like market power, whether there's an approved IRP that demonstrates a need or not for any additional capacity? All of those kind of things that they've outlined? Or -- I just want folk's reaction to that, kind of general thought that NARUC has teed up.

MR. SIPE: I think first off, you've got a statute that basically tells you, you know, when you can give those exemptions and when you can't. And that's where you need to start.

I'm not sure that the Commission can delegate that authority under the statute to estate, to make the decision whether it thinks there's, you know, exercise their market power or other things, I think that's ultimately got to be something that you've got to look at yourself.

I think the interpretation of 210(m) is already fairly generous in the RTO market when there really isn't quality assurance on the market. We may have access to it, but I agree that, you know, one or two-year product isn't something that we can sell into.

I'm not sure the fact that the market monitor found there isn't, you know, market power concerns means that there's an opportunity for us to sell into that market. So I think fundamentally those are types of things that you might look at in making a decision under 210(m), whether or not those markets are reasonably competitive.

But I don't think you can ever turn that finding over to a state to have a state declare that, "Oh, we think our markets are competitive enough." And I think that's just the basic jurisdictional issue, that Congress is giving you that role.

You should, I guess, listen to any argument that our markets are competitive, but that ultimately, the standard's got to be set by you.

COMMISSIONER CLARK: Liz?

MS. WHITTLE: Thank you. He covered a lot of the things that I was going to say. I think, in terms of -- I think the presumption, actually has worked pretty well in ISO New England from the perspective of our small existing hydroelectric generators in ISO New England, they crave certainty and so I think that weighs against too much creating exceptions that would be permissible within the statute, but then again, there's always something quirky that comes up, no matter what you do.

And that's why you have the standards under the open access transmission tariff for regional differences and that sort of thing. So, but I think a firm guidance and in particular on our issues, is what we seek, but I don't think that should be delegated to the states.

COMMISSIONER CLARK: And I think my question is more to the, in the context of whether there needs to be more clarity with regard to shorter term of what it, cost calculations, as opposed to an exemption from the mandatory purchase obligations and whether if there is some sort of clarity that needs to be brought as Charles mentioned. I mean there's some diversity of opinion on whether it's five minutes or fifty years or whatever the length of the contract is.

But if we decide if there needs to be that clarity, then do some of these things that NARUC has outlined in terms of whether solicitations are held and whether they're genuinely competitive in the IRP, whether the utility and its IRP doesn't forecast a need for a certain period of time for any capacity, if that, if those kind of bounding principles make sense.

COMMISSIONER RAPER: First of all, I apologize for overlooking the dissent, because I want to keep peace in Idaho that kept us afloat, I think, for a while, while everything was going on. So, thank you.

I generally refer to Travis as wicked smart. So I'm going to say that yeah, I think that NARUC has some good ideas on those elements. Unfortunately, I think that trying to implement those causes a rewrite of FERC regulations, which at least to the extent that we prepared for these technical hearings.

We were trying to work within the structure that was given to us to, you know, canoodle what we could and kind of make it fit. So I think they're great ideas. I think that they would certainly alleviate some of the issues that we've had in the State of Idaho. I just think that it would probably cause a rewrite of some of the statute, which you're going to get a lot of input on, so --

COMMISSIONER CLARK: Statute or rules?

COMMISSIONER RAPER: Rules.

COMMISSIONER CLARK: Thanks, Jeff?

MR. BURLESON: Yes, so Commissioner, I was just going to address one or two of the items that you brought up. One, specifically capacity need for us, we generally will pay capacity for QFs starting in the year when we have a capacity need on our system.

And we will pay that capacity need continually and throughout the term of that QF contract. The challenge for us as an example right now is, we don't have a need for incremental capacity on our system until the year 2024. And so we don't see that it would be helpful for us to enter into a QF capacity contract today that would start paying capacity payments immediately.

And so I wouldn't want to see the Commission do anything that would change that kind of a construct or prohibit that sort of thing. Some of our states do, however, allow for larger QFs, particularly where it's not a standard contract, to accelerate some of the capacity payment by lowering the long-term, so that the present value of the capacity payments over the term of the contract are unchanged.

That we would be relatively indifferent to, but we don't see that it would be helpful for our customers to start paying for incremental capacity from QFs when there is no defined capacity need on the system. So that's one.

And then secondly, again, as I had mentioned previously, I think the term lengths are okay, particularly longer term contracts are not something that we're afraid of. The challenge for us is, we don't think it's a good idea to lock in full long-term avoided energy costs projections for very long-term contracts. And there are many ways in which that issue could be addressed while still keeping the contract term lengths long enough for QFs to be able to get financing.

COMMISSIONER CLARK: Thanks for that clarification, Todd.

MR. FOLEY: I was just going to reinforce just the importance of the long-term contracting for renewable energy resources, and you know, without, you know, sufficient length, or you know, again, these are things probably don't get financed, or have trouble getting financing, but, and Jeff, you just, I think there may be some things that can be factored in to help on that.

One is what we can do to be more accurate or do even a better job at looking at avoided costs. I think again when we think about resource planning, looking at again, a portfolio, I think it's been talked about the market impacts today on, you know, the portfolio and contracting, where we can't always be sure where prices are going, but there is some value.

You're locking in some long-term, and there's some value in maintaining flexibility in the near term, so I think an appropriate mix of these things is very important, but if we want renewables, I think to continue to contribute -- there are many ways that we are now including directly with utilities outside of PURPA, that's on -- but for some elements of the market as well, PURPA remains important on that front.

COMMISSIONER CLARK: Don and Elizabeth, did you want to circle back on this?

MR. SIPE: Yeah, and I apologize for not quite understanding the question at first. I think that we have to accept that Congress did intend to shift some of the risk away from QFs on these markets, and allow rate-payers to pick up some of the risk comparable to what they would pick up with utility projects.

And as I started out saying, you know, markets are not risk-free. Relying on a market, you're paying a premium there. What markets do to manage risk better is by putting it on the people that can manage it fast, that can do operational things or other things that manage that risk. They don't get rid of it. If you look at the goals of PURPA, which is to encourage QFs, but also, you know, to make sure that rate-payers are protected --

If you're trying to encourage QFs and you actually get them built, and they're built in the market, they're going to have a much higher risk premium, and if you get them built, you're going to have to pay that risk premium. That isn't -- you don't get that for free. If they're out there in the market.

So when you look at who can manage that risk better, if you're Congress and you're looking at "how do I manage that risk to make sure that person that has the best chance of managing that risk and predicting it has the balance?" Is it some 20 megawatt QF out there who's trying to predict a twenty-year forward price curve? Or is it perhaps a utility with a lot of analytical skills in planning a lot of other projects and doing other things?

So I think we've got to get avoided cost right, but I think we've got to accept the fact that that risk is going to be managed better to get those QFs into the market under that scenario than it would be if we said, "You just got to go out in the market and either not get built or take a market premium risk," because I think the premium on risk is going to be much lower under Congress' model, which means we're going to pay less.

Provided we actually get these things built. If we don't get these things built, then we're not encouraging QFs. So, you know, those are the sort of the two ways that they could get built. And I think there's lower risk and lower cost with the way Congress has it set up, than if we had these 20-megawatt guys out there running around in the market trying to predict the future on their own. What's your banker going to charge you? If it's financeable at all, that's very costly.

COMMISSIONER CLARK: Elizabeth.

MS. WHITTLE: Okay, I'll be brief. I know it's getting late. First of all, again, some of the standards, I think that were presented by NARUC look to more than what would constitute the avoided cost of the utility, and that's what the statute requires. So I think, to that extent, that's kind of in the Commission's wheelhouse to come up with some guidance on that front.

The other point is that, even utilities in RTO markets purchase electricity, and when they purchase it, there is a risk premium that's included in that purchase. And that gets reflected in the overall price that they pay for their product, that they then supply to their load.

So there are ways in RTO markets, and it's not the real-time L&P or the Day Ahead L&P. It's that plus whatever all the other components are that go into their procurement of energy to serve load. And that's the avoided cost that we're looking at this point to try to clarify.

And the final point I want to make is, I agree with the representative of Southern Company, you know it is a reasonable approach to negotiate a contract, because what we're talking about here was setting avoided costs.

In many instances is when you can't reach agreement with the utility, entities are always free to contract at a different rate, and I guess Southern Company does at rates that are below what they consider to be their avoided cost, but we still keep that flexibility, I think that we haven't really talked about today because we've been assuming that all purchases are made at avoided cost rates and I really don't think that is true today and I don't think it was true when QF80-1 was filed.

COMMISSIONER CLARK: Thanks to everyone for the clarifications.

MR. GREENFIELD: Do the Commissioners have any further questions or statements?

(no response)

MR. GREENFIELD: Well, I know we could go on for, well, hours probably more with more questions, because I know some of my colleagues have indicated that if there's time, we would have more questions. I suspect at this point we probably have taken advantage of you all for long enough. Let me thank you, let me thank the first panel of speakers. You all have been very helpful, as the first panel was.

And we do appreciate your taking time out of your schedules to come here today. Let me thank the Commissioners, let me thank my colleagues at the table, and those who couldn't be here today and I think with that, we are adjourned. One last comment.

MS. WHITTLE: Are you going to provide an opportunity to collect comments outside of what the speakers provided, right before the Technical Conference?

MR. GREENFIELD: I think we're going to go back and caucus and think about what we heard today and what would be the next steps, in terms of how as an agency we want to proceed, because there are a lots of issues that have been raised, so I think we're going to need to think hard about what we want to do next. Thank you.

(Whereupon the conference was adjourned at 3:33 p.m.)

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This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding:

Technical Conference on Implementation Issues Under The Public Utility Regulatory Policies Act of 1978

Docket No.: AD16-16-000

Place: Washington DC

Date: 6/29/2016

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcripton of the proceedings.

Gaynell Catherine

Official Reporter