FEDERAL ENERGY REGULATORY COMMISION

OLD DOMINION COOPERATIVE

DOCKET NOS: EL17-32-000

EL17-36-000

PJM SEASONAL CAPACITY

TECHNICAL CONFERENCE

888 1ST Street, NE

Washington, DC 20426

Tuesday, April 24, 2018

9:30 a.m.

APPEARANCES:

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P R O C E E D I N G S

(9:32 a.m.)

MR. MONICK: Good morning, everybody. I would like to welcome everyone to this Technical Conference on Seasonal Capacity and PJM. My name is Noah Monick with the Office of General Counsel.

Today's Conference will focus on the issues raised in the complaints filed by Old Dominion Electric Cooperative Direct Energy Business, American Municipal Power and Advanced Energy Management Alliance against PJM Interconnection, LLC and Docket Nos. EL17-32 and EL17-36.

I would like to thank all the participants for joining us today. This Conference will be led by Commission Staff and any comments here represent the views of Commission Staff and not the Commission.

Also we will likely issue a request for comments after the Conference with questions for follow-up, so please be on the lookout for that. Before we begin, a few housekeeping announcements.

Please turn off your cell phones or put them in airplane mode. No food or drink other than water is allowed in the Commission meeting room. There are bathrooms and water fountains behind the elevator banks on each end of the building.

This Technical Conference is being webcast and transcribed as stated in the notice. For the panelists as well as the staff members, if you'd like to be recognized to speak just place your tent card up on end. If you could please introduce yourself before speaking that would be helpful for the transcriber.

Remember to turn your microphones on when speaking and speak directly into them and turn them off when you're done. I'd like to remind everyone of the Commission's ex parte rules. This Conference will cover the topics discussed in the notice related to the complaints in EL17-32 and EL17-36.

Please avoid discussing the meds of any other on the record contested proceedings. We will have three panels today, the first panel which will run until 11:00 will cover peak shaving which refers to the reduction of consumption during peak periods to lower an entity's capacity obligation.

Specifically the panel will review current practices in PJM to account for customer Peak Shaving efforts in the PJM footprint and discuss possible alternatives. Then, after a short break, we will have the second panel from 11:15 to 12:30 on Loss of Load Expectation or LOLE which refers to the probability that the grid operator will need to shed load because of an inadequate amount of capacity.

This panel will discuss PJM's current LOLE risk allocation practices and how PJM accounts for outage related factors in its LOLE calculations.

Finally, after lunch, we will have the last panel starting at 1:30 on Seasonality, specifically the advantages and disadvantages of procuring capacity under alternate LOLE allocations along with possibilities for shifting capacity procurement to a seasonal based construct.

That panel is scheduled to run until 4:15 but we will likely have a short break in the middle. I'm joined today by a number of exceptional Commission Staff members who will introduce themselves.

We start at the end and go around.

MS. WIERZBICKI: Mary Wierzbicki from the Policy Office.

MR. RAMLATCHAN: Deepak Ramlatchan, I'm in OEMR East.

MR. MEAD: I'm David Mead in the Policy Office.

MR. KATHAN: And I'm David Kathan from the Policy Office.

MR. ROLASHEVICH: Pete Rolashevich Office of Energy Market Regulation, East Division.

MR. RIEHL: John Riehl, Office of Energy Market Regulation, Eastern Division.

MR. GOLDENBERG: Michael Goldenberg, General

Counsel's Office.

MR. COOK: John Cook in the Policy Office.

MS. LAZERWITZ: Briana Lazerwitz in the Police Office.

MR. FEUERSTEIN: Jason Feuerstein, Electric Reliability.

MR. MONICK: Thank you, joining us today for our first panel we have Marjorie Phillips from Direct Energy Business Marketing; Bruce Campbell from CPower; Tom Falin from PJM; William Fields from the Maryland Office of People's Counsel and Joseph Bowring, the Independent Market Monitor for PJM. And thank you all again very much for taking the time to come to be here with us today and share your expertise. We appreciate it very much.

We would like this event to be a conversation rather than a collection of presentations so why don't we start with the first question from the supplemental notice -- what is the role of peak shaving where demand can alternately reflect its peak needs, via demand response, energy efficiency and price responsive demand?

Further, how does PJM account for the effects of these products in its capacity market given their impacts in the energy market?

As a reminder if you could please introduce yourself before speaking that would be helpful for the transcriber and why don't we -- Tom, would you like to start?

MR. FALIN: Okay sur, Tom Falin from PJM. I appreciate the opportunity to be here this morning. In my mind peak load shaving is kind of two types. The first type are those programs that are able to participate in PJM markets whether it be capacity and energy or ancillary services. For those programs we have a very good handle on when they interrupt, what megawatt amount and the duration.

And so I think we factor that correctly into our load forecast model. However, the second type of peak load shaving which I think is the focus of this question, is that -- that does not participate in the PJM market so the interruption is really initiated by the end user.

So PJM receives no information from the end user because they really have no obligation or even incentive to kind of inform PJM about what the curtailment was and how long it lasted. So that particular type of peak shaving is really captured in our load forecast model to the extent that it's reflected in metered load history.

Obviously if peak shaving is going on, our meter load history will be lower. So I think I would argue for the peak shaving going on today, I think our forecast model picks that up pretty well.

And the reason I say that is because at the end of each summer we kind of do a benchmark of how accurate our load forecast was for the previous summer and if you examine what the forecast model error was on a three year ahead forecast basis, which is the horizon for RPM, the mean absolute percent error is 1.6%.

And then actually the mean error is 1.2%. So those -- you know two numbers are I think fairly, fairly good and the fact that the mean absolute error is higher than the mean error actually shows that sometimes we under -- we under forecast, sometimes we over forecast, so it's kind of an unbiased model.

And I think it's reasonably accurate. So that's how we handle the current peak load shaving that's going on. I think it's being picked up pretty well. However, I think if some capacity market rules change and there's reason to believe that the peak shaving behavior will be different in the future than it has been in the past, you know, that's something PJM would definitely want to get in front of, you know, and be able to pick it up in our load forecast going forward.

So currently there's actually a PJM stakeholder group, summer only demand response senior task force that is looking at this exact issue. How can we recognize the value of summer only DR if they're no longer able to participate in the RMP capacity market?

So on that front the stakeholder group is working on a number of proposals -- a number of alternatives to somehow, you know, anticipate what kind of peak shaving might be going on in the future. I think for PJM's comfort level we would like some sort of assurance as to yes, those interruptions will occur based on certain triggers and they're committed to actually interrupt for certain number of times per summer, certain hourly duration.

So all of those kinds of points I think are being worked through the stakeholder process so I'm optimistic that if peak shaving behavior changes in the future compared to what we've seen in the past, I think that this group that's due to wrap up -- I think its work, by the end of this year.

So any change coming out of that would actually -- should be in place for the base residual auction to be run in -- in May of 2019. So that's kind of the current state of peak load shaving and how we recognize it currently in the PJM forecast model and then potentially any changes going forward.

MR. MONICK: Bruce?

MR. CAMPBELL: Thank you, this is -- I'm Bruce Campbell with CPower. First of all I want to be -- define some of the discussion. I view peak shaving as the load curtailments that are not part of PJM's model and/or market product per se. In fact peak shaving is not a product.

Peak shaving is an activity. Some might characterize demand response resources as engaging in peak shaving -- I don't. I view demand response resources curtailing as -- as meeting a product requirement -- so just that's just a clarification item.

I think to follow-up on some of Tom's comments, PJM's -- well let me back up. Peak shaving does occur today primarily I believe, with large industries who are the kinds of customers that my company serves. And those large industrials do peak shaving to manager their -- their capacity costs in some cases transmission costs.

There's another -- with the implementation of CP, of capacity performance product, the new PJM arrangement that is the subject of the complaint, one of the things that have happened in seasonal resources -- resources that can only perform in the summer really can't deliver a product anymore so they are out of the market.

PJM has suggested that those resources could keep -- manage their capacity costs by peak shaving. And so part of the issue here becomes is how -- what happens with the peak shaving?

In PJM today load forecasts don't accommodate peak shaving or at least as Tom alluded to, changes in peak shaving behavior. So PJM has suggested that programs like residential demand response that are air-conditioner based, can reap the benefits of their curtailment activity by peak shaving but as Tom suggests, forecasts today don't accommodate that change very well.

It will take years for peak shaving to be reflected in load forecasts absent the kind of changes that are being discussed. So that's one element there and I think there are some issues as Tom suggested with what about the certainty of that sort of activity -- residential and mass market load programs?

How about in mecca non-mass market programs, my customers could engage in continued -- many will continue to engage in peak shaving. Will they change their behavior? I don't know. Some customers might. Will they get reflected in the load forecast? Probably not because we don't -- I don't believe that PJM will have a mechanism to pick that up that would be unpredictable and just not forecastable.

I question whether even residential load programs could be adequately addressed because they are subject to riders, they're not necessarily definite -- sometimes they're five years programs, a whole variety of things and of course not every state has them.

So there's a bucket of resources that could be affected. I want to touch on one other thing and I think PJM has alluded to their load forecast here. And I think we should be clear that at least my understanding and Tom can differ from me -- provide a better explanation.

When the load forecast -- when PJM says their load forecast area is very small what they mean is if we go back and took the inputs that should have gone into it like economic growth, the model works. So they back pass, look at economic forecasts that should have gone in rather than the economic forecasts that did go in and say that their forecasts are accurate.

Their models work in that respect but the inputs may not be all that great. And certainly load forecast and you want to back pass like that you can say your load forecasts have been -- in some cases high and in some cases low. My records indicate in 10 years that RPM has been in place that PJM has never done a three year forecast that was low, be that as it may, thank you.

MR. MONICK: Marjorie?

MS. PHILLIPS: Marjorie Phillips. I'm here -- so just to give you a little context. My company does do demand response. My comments here are really more coming from a load-serving entity perspective. It's kind of ironic that I am the least technically adept on this panel but I'm going to take a shot at answering your question and figuring that PJM or anybody else can then correct me.

The problem with the peak shaving is that PJM uses a weekly forecast so it looks at what do we have -- 52 weeks a year? So it looks at how much is used every week and it uses -- I don't know if it's a 5 CP or a 10 CP curtailment, so you could curtail five times during the summer. That leaves a lot of other weeks where you are not curtailing.

It doesn't get factored into the forecast. It takes 18 years -- 18 years to get about 50% of the reduction factored into the forecast. And from a load-serving perspective the concern here is that even when the customer gets individual credit for peak shaving, it doesn't impact PJM's capacity procurement.

So I don't really care how well PJM's forecasting, I can tell you they have over procured for years and consumers pay for that. And so the problem is the one customer's costs go down but PJM continues to procure that capacity because it's not reflected and captured and so the costs of that capacity are simply socialized among what I would call our remaining customers and that is the concern about modeling and recognizing PRD.

As Tom says, they're working on it but that is as I understand the basic challenge of PRD today in terms of capturing its value.

MR. MONICK: Why don't we go to William and then Joe and then we'll come back to Tom.

MR. FIELDS: Thank you, Bill Fields with the Maryland Office of People's Counsel. The reason we filed comments and asked to be part of this panel was that we're concerned about the value that our customers are able to achieve through the peak demand reduction efforts that we undertake now through state programs.

There's air-conditioning cycling programs, to a lesser extent hot water heaters and then we are developing or we have and continue to develop what we call behavioral programs which are based on the new AMI metering and peak day signals that tell customers to reduce and they can get a rebate for that.

The -- with focusing on the air-conditioning cycling that used to be a product that could be sold as capacity, produce revenue for the load serving entity which is going to be the utility. And then that would cover the costs of whatever financial and the costs of the program including the financial incentives that are required to motivate customers to do that because there is obviously a cost to undertaking whatever peak shaving effort you're going to undertake.

And you know, that made the process relatively straight-forward to say this is cost-effective. In Maryland we have a law that requires these types of efforts to be done on a cost-effective basis and I'm sure regulatory authorities all over would be looking to be sure that this was done cost-effectively.

With capacity performance, that has transitioned to away from being able to be a product because it's -- the performance is measured not against your annual capacity requirement for those customers but it's measured with respect to how much the load drops in each individual event. And that's not a problem for the summer but it's a problem for the winter obviously because you're not going to have the same kind of response in the winter -- you might not have any response.

And so that leads to a few concerns for us. One, which has been talked about a little bit, we've heard through stakeholder discussions this -- what Marjorie has just referred to if we transition that type of ability from being reflected in the market to just being reflected in the meter load it's going to take 18 years for half of it to be reflected.

And that's, you know, that's going to be -- it's going to be a hard sell to say that you know, we ought to take -- make an effort and pay incentives or whatever we need to do to reduce that peak load and we're not going to see any real benefit from it for decades.

That's one, you know, issue that we have. The second concern that that raises, well if you do -- if you do transition that we have the ability to do some of this as PRD which is -- which itself produces some value in the wholesale market by reducing the overall procurement which is good for the residential customers.

It makes it more complicated at the state and the retail level because the value is not revenue anymore, value is now reduction and how much you have to pay and sure you can do an analysis of that and you can -- you can look at that, but with any analysis there's assumptions and there can be difference of opinions and it gets more complicated to justify that this is really cost-effective and, you know, that can be -- that can be an issue although it's still, at least from our perspective, there still is real value as long as you are reducing the overall amount of capacity procured.

As Marjorie alluded to or talked about when you just look at the divvying up of that capacity obligation between customers -- sure if you -- if you reduce your 5 CPs you can reduce the individual customer's capacity obligation. And as Marjorie said that just shifts it over to other customers which are probably going to be the residential customers that I represent because they're not going to see that reflected in the capacity obligation that they're -- that they're having to pay for on an on-going basis.

So those are our concerns. We think that as Tom alluded to there's discussions in the stakeholder process that, you know, the real issue that we see -- one of the real issues that we see is this definition of performance for a demand response resource and whether you are measuring that against the annual peak load for those customers or some kind of winter load, then from our perspective we're buying -- if we're being asked to buy that annual capacity -- annual peak load capacity and we're asked to buy that throughout the year then we really should have -- be able -- we should be able to measure our winter load against that annual peak and show that it's come down from the annual peak even if there's not a specific action of performing in the winter.

You know, otherwise, if our peak load is -- if a customer's peak load is 100 and can bring it down to 90 over the summer and then the load is just naturally 80 in the winter, you know, if we lose the PRB ability or lose any value from the wholesale market, then we're essentially being asked to buy 100 and pay for it throughout the whole year when we can bring it down to 90.

And the fact that our load is 80 in the winter doesn't factor into it anymore -- it doesn't matter. And if that becomes the case then it becomes very difficult to make the case to customers or, you know, to a state commission, however it's working out to say well you ought to reduce from 100 to 90 when you're still having to buy 100.

So those are our concerns and thank you for inviting us to participate today.

MR. MONICK: Mr. Bowring?

MR. BOWRING: Alright, Joe Bowring, Monitoring for PJM, thank you for the opportunity to participate in the Technical Conference today. So peak shaving in my view I think that's the basis of the Technical Conference here is a reduction in load outside of a formal DR program.

But I would also hurry to say that that doesn't mean you're not participating in PJM markets -- clearly you are. In fact in my view, peak shaving in that sense is the best form of DR. It's not bound by CP rules, it simply responds to price. It's an actual real reduction it's based on you get paid, they send you a metered load, there's no measurement and verification. It's a function of meter load at the 5 CPs.

So a couple of the issues with peak shaving that we will address that are commonly -- commonly known issues having one to the forecast. PJM is working on that. PJM is talking about different ways to do the forecast using for example, THI instead of historical usage on peak.

There are ways to make that happen. Clearly in order for peak shaving to work as a product -- as an alternative to participating in a DR program with complicated CP rules, a couple of things have to be true.

First of all you have to be able to respond to the price. You have to be able to get an immediate payment of that for a reduction in a reduction payment -- same idea. And it has to immediately affect the forecast -- it can't be an 18 year lag, it shouldn't even be more than a year lag, it should immediately affect the forecast.

I don't think that peak shaving folks, any more than any other customers should commit to doing peak shaving. They're market participants, they're responding to price. PJM could deal with uncertain outcomes. It's fine if PJM folks want to provide that information to PJM about what their plans are, that's great.

But there certainly should not be a commitment. The point is it's a response to a market price and that's the way markets -- markets should work. PJM should also be required to provide better information to participants about expected times of peak loads so people can reduce when they need to, but the key thing is the immediate information feedback.

A couple of -- another key thing about, a key fact, a key element about peak shaving that was talked about a little bit is it depends on peak shaving to be functional depends on some really strong assumptions. For example, it depends on the assumption that all capacity costs are associated with one hour.

When you think about it, it's kind of a not very accurate, not very correct almost surprising conclusion, but nonetheless, that's how PJM allocates capacity costs to one hour of the year.

And then typically LSE's spread that on using 5 CP but that's equally non-intuitive, equally nonsensical I would say from an economics perspective. Imagine that we actually went to a summer/winter capacity market. That will change the entire nature of peak shaving and it will change the entire incentives for peak shaving because some capacity costs will be allocated to the winter.

So instead of being able to peak shave based entirely on summer CP's or expected CP's it will affect, you will have to also peak shave in the winter depending upon how capacity costs are allocated.

So peak shaving to work -- that is peak shaving in the broadest sense of responding to prices, will depend on the allocation of capacity costs across the year however that turns out to be.

At the very least, allocations of capacity costs should include the 1 CP, the 5 CP but also performance assessment hours. So performance assessment hours obviously are a means in the year and affective in an emergency shortage in PJM.

And if it's really the case that there's a lot more DR in the summer element of PJM capacity market, and it continues to be true that DR simply by being called triggers the performance assessment hour, there's going to be a lot more performance in the summer hours which means something about the incentives and economics of peak shaving, thank you.

MR. MONICK: Tom?

MR. FALIN: Okay, thank you, Tom Falin from PJM. On just a couple I guess comments to some of the remarks from my colleague. I think that Bruce Campbell and I were actually not talking about the same kind of load forecast error.

I'm always careful to use the term load forecast model error, okay, which is different than the load forecast error. So the load forecast model error that I cited as being about 1 % mean absolute error, that's based on at the end of every summer we now know the actual weather that summer, the economics, the energy efficiency, the behind the meter solar -- so we'll take all those known variables, plug it into our model for each of the top 10 load days of the year and compare the load that our model produces with the metered load we saw on that day.

So that's sort of -- we've isolated the model error by kind of removing all the uncertainties from those external variables. So I think in terms of trying to gauge if we're currently picking up load shaving well or not, I think that's the more meaningful metric to look at given the system conditions on that day, how good is our model at taking the known inputs and predicting the load we saw on that day.

On a larger point I guess I heard some of my -- you know, colleagues refer to the 18 years of history that it takes to recognize peak load shaving. All of that is actually based on analysis that stakeholders had requested from us.

They essentially asked us to go back and pick the 10 highest peak load days from each of the last 18 summers so they're called the 10 CPs, the 10 coincident peak days. Pretend the peak load shaving had been occurring on all of those 10 CPs and see how much the load reduction is.

It's true -- it's not going to be one to one. However, as PJM has kind of said at several stakeholder meetings, if your goal is to reduce the load forecast the strategic way to peak load shave is to not just blindly choose the top five CPs or 10 CP days each year.

It should be instead targeted on the temperature humidity index, the weather parameter we use, so if you can picture essentially the model is your regression of weather against load, so it has an upward sloping line.

The peak load -- the 50/50 peak load forecast is really going to be driven only by the data points on the far right of that line when the temperature humidity index exceeds about 83 or 85. So if you were to have a very, very mild summer, interrupting on those 10 CP days is not going to really affect any data point that goes into the portion of the regression that matters.

But in another summer if you have extreme heat and perhaps there are 15 or 20 days that it would help you to curtail on all of those days, it would have a bigger effect. So I think that's part of the reason why it takes so long to work itself into our model. Just choosing the top 10 load days of the year is not the most effective way to peak load shave.

The other point I guess for the reason for the kind of -- the lag in the recognition of the load reduction is really because of the phenomenon of inter-day and intra-day peak shifting. So for instance if the -- if the peak day of the year were 150,000 megawatts and the second highest peak day were 148,000 megawatts, if a lot of peak load shaving is going on on the peak day -- say it's 5,000 megawatts, that drops what had been the peak day from 150,000 down to 145,000 that's no longer the peak day, it's what had been day 2 now takes over that spot.

So the effective reduction is really only 2,000 megawatts. Why? Because the day of the annual peak is actually shifted to another day so and then that same phenomenon could happen within a day also -- under summer conditions we typically peak at about 5 P.M.

If a lot of peak curtailment comes on at 5 P.M., perhaps the daily peak will shift to 1 or 2 P.M. So I think the amount of recognition that you get for peak load shaving is partly related to how many other customers are doing the same thing at the same time. And the more peak load shaving you have happening on a given day or a given hour of the day, the less the overall RTO load reduction will be.

So there are certain technical aspects of our model that we try to explain at stakeholder meetings why it has that very diluted effective 18 years. But again, I guess I would get back -- back to the stakeholder process that the group is working on now. I mean PJM acknowledges that if peak shaving behavior were to fundamentally change in the future, you know, perhaps the proper way to do it is not just wait until that peak load shaving happens and accumulates over the next 5, 10, or even 18 years, but somehow you know, figure out what the load reduction should be considering those other two factors about interrupting based on whether and the risk of shifting the peak across days.

And then perhaps make a discreet adjustment -- a downward reduction to the load forecast to kind of recognize that that peak shaving will occur in the future.

MR. MONICK: We're going to hear from Marjorie and then Bruce and then we'll see if we have questions from the staff, thanks.

MS. PHILLIPS: So Marjorie Phillips. I'm going to cut to the chase about why we're here because you don't have me on any panel later for me to talk about it. So there is a bias in PJM against including demand response in the capacity market.

It's a legitimate concern that capacity revenues are not sufficient to compensate generators. One way to get them up is to kick DR out. What you have heard today is that PJM is going through all sorts of machinations to make this peak shaving "work".

Tom admits that there are problems with the modeling. He didn't deny that, you know, they can't capture everything. And so we're in these stakeholder processes giving all these sort of convoluted things. Why wouldn't you want a summer demand response product? You can measure and verify it. You can dispatch it. You can control it. PJM has done it already right?

So we're doing all this stuff for PRD and it's to push demand response out of the capacity market. Why do you want a product you can't see, you can't dispatch it and you have to go through all these forecasting machinations that they're going through to make it work.

There are some very good state programs that do have PRD and they shouldn't be eliminated and they should be recognized, but there are so many more efficient ways to capture demand response and to reduce the capacity procurement which is good overall for customers, thank you.

MR. CAMPBELL: Thank you, Bruce Campbell with CPower. I just -- I did want to respond to Dr. Bowring's comments about peak shaving and its proper place in the market design. And I wouldn't disagree with Dr. Bowring with respect to the rational buyer behavior kind of argument that supports that recommendation, but I would comment that the payment for demand response has been very, very successful in bringing a lot of demand response resources to play.

And that one could say well rationally peak shaving should work just as well as demand response but in the real world it doesn't. And I think peak shaving is a very, very poor second best approach to demand -- to getting customers to respond to -- to peak demands in the system. And that supplements Marjorie's comments that demand response is very successful as a product, peak shaving is not a product it's a behavior, thank you.

MR. BOWRING: Thanks, I agree that peak shaving is a behavior and not a market product and that's sort of the opposite of what Marjorie was saying. I mean to hold out CP is a non-complicated alterative to peak shaving -- it's kind of odd when you think about it.

I assume you've read the rules lately in CP -- it's not easy to do it and that's part of the reason we're here is because DR doesn't fit well as an annual product. What I'm suggesting is that DR would work a lot better if it were outside the formal CP market but still facilitated in such a way that the participation was even better than it is now.

But to hold out DR as a successful program when in fact we've demonstrated that it is suppressed price -- I mean just think about it, it's an emergency-only resource. Imagine if you had -- if your entire reserve margin were made up of demand side, that means you'd be in an emergency all summer long.

It's not an -- it's not treated as an economic resource even though it's competing with other economic resources. It's hardly to be held out as a paragon of good market design. So I think one of the issues that comes up if you think about summer/winter is what really is the definition of DR -- how should it best participate in the markets?

In my view it would be better to let customers make up their own minds, respond to price, ensure that the forecasts are fixed immediately, ensure that there's a price reduction immediately, insure that they get good information that will allow them to do that and then you don't have to worry about measurement verification, you don't have to worry about all the complicated definitions in the capacity market, thanks.

MR. KATHAN: Hi, David Kathan. I had wanted to follow-up on some of the comments that Mr. Fields was saying having to do with the load serving entity or electric distribution company, direct load control, various types of summer-based demand response.

Many of these programs, especially in the mid-Atlantic have been operating for decades. So my question to PJM -- to you Tom, is -- how are those summer programs -- these are, you know, air-conditioner cycling programs. How are they reflected in load forecasts and these have been in operation for, you know, many years, there's lots of data on their operation.

How are they integrated into the forecast?

MR. FALIN: Tom Falin from PJM. Well in those cases I guess that's sort of occurring behind the meter so PJM just sees the impact of that in terms of a reduced load I take it.

MR. KATHAN: That's correct.

MR. FALIN: Right, right, right, so that would fall yeah -- so our metered load history is obviously lower because those actions have been going on. And again, I kind of get back to the fact that, you know, that our forecast model error is pretty low right now. I think it gives me some comfort that our current load forecast is picking up the existing peak shaving programs.

Again, because if we check after the fact to see how close is our model how good is our model at taking the known inputs and matching the load we see on that day it's rather close. So to answer your question I guess there's no explicit adjustment to the load forecast model mainly because we don't necessarily have the data that says what megawatts were interrupted for how long and over what days.

But the fact that it's been going on now for several years and is already kind of baked in to the metered load history, that's a direct input to our load forecast model. So I believe that, you know, as of now our forecast is pretty good at reflecting that activity.

MR. KATHAN: Just to follow-up on that question which is you're talking about PJM that's load forecast throughout the full, you know, service area, is that correct?

MR. FALIN: Correct.

MR. KATHAN: And so what about specific service territories, for example, Palmer Gas Electric or Tapco who have been operating these direct load control programs, what is that -- is that the similar experience with their forecast?

MR. FALIN: Okay, I see your point. Yeah, we would have to actually measure what the pure load forecast model area is for each of those zones. The one thing we do check though is what comes out of our load forecast model is obviously a forecast for the entire RTO and then that's allocated kind of to all the zones.

So we took a look at what percent of the RTO load does each of our transmission owner zones have and then we compared that to history okay -- 10 or 20 years of meter load history, figure out what's the average contribution of each zone to the PJM's overall peak and that number was within a tenth or a two percent of our forecast model allocation.

So trying to analyze it from that angle I think we had some comfort that not only is our forecast model error for the overall RTO pretty accurate, but when we allocate that out to zones it matches very well with the metered load history of the last 10 or 15 years.

MR. KATHAN: And one last question as follow-up is so think about direct load control and as Joe was talking about are their emergency-based programs. So these may not happen for many years, you know, probably the last time there's been an emergency or some of the direct load controls have been executed has probably been several years ago.

So you may not see that pattern showing up in the load history. So you have the capabilities there but it's not showing up in the load forecast, is that correct?

MR. FALIN: Well are those load programs now qualified as DR in the RPM auction?

MR. KATHAN: They had been.

MR. FALIN: Oh they had been okay, so then the ad-backs have gone in for those so any kind of interruption that had occurred with them they would -- the customer would supply PJM with the amount of load that was interrupted. So that has been added back into our load forecast history.

So in that sense it would not be reflected but again I think that's part of the issues that the stakeholder group is looking at. What happens if you deal with a certain load interruptible customer who used to interrupt their load and then for whatever reason then was not part of RPM but will intend to peak load shave in the future.

I understand that kind of behavior should be reflected in the forecast going forward so I think that's exactly the subject of the discussion of the stakeholder process -- how to handle those types of programs.

MR. FIELDS: Thank you, Bill Fields, Maryland People's Counsel and I'm glad you asked that last follow-up because I was going to bring up the point about the ad-backs and I wasn't totally sure I was going to be right.

But I think what's happened is that with those programs that we were talking about, the Maryland air-conditioning cycling programs, they have been bid in as demand response into the capacity markets and when that happens that load reduction is then added back into the load when they do their load forecasting so that if -- if the DR stopped happening, you know, you wouldn't be under procured because you were assuming that it was going to be there and they just decided to stop doing it.

So it's added back in so that it's not -- the reduction is not reflected. And so if that now becomes or is not able to participate in the market and just becomes this, you know, peak shaving type of resource, then you have the issue where that's a change in the peak shaving behavior that's not captured by the -- under the current methodologies, it's not captured by the load forecast.

As far as the -- you talked the programs just one point about that. They are only obligated to run as emergency resources on emergency days. They do run them other times. They run them for testing, they run them periodically through the year to sort of avoid the issue of, you know, they haven't been called for three years and then all of a sudden they call it and people don't really remember what's going on.

We had an issue about that a few years ago but sort of the protocols have been changed a little bit and to some extent because the market is changed, they are called more often than that now. Thank you.

MR. RIEHL: As for the two remaining questions on our peak shaving panel I was wondering if each of the panelists would comment on that and then I do have two follow-ups after you've spoken to them.

Oh yeah so questions -- are there reasonable modifications to these products that could be alternatives to modifying PJM's load forecasting methodology? I believe you all previously touched on some modifications so if you could go over them again in further detail, Marjorie?

MS. PHILIPS: Marjorie Phillips, so I don't want to take away from the future panels because they're more technical but as you know you probably may recall in the ODEC AMP direct complaint and responses to the Technical Conference, we have proposed bringing back a summer demand product.

I'm not going to get into the technicalities -- I think Mike Cocco and perhaps Steve Lieberman are on the future panels to talk about how that would be done by changing the forecasting assumptions. Let's just reiterate for basics, the PJM capacity structure was developed 20-25 years ago when everything was a base product.

And there are assumptions in it that those units run 24/7, they don't. Nuclear units take 6 weeks, 4 weeks outages -- they still are assumed to run 24 by 7 -- so just giving a little historical context. Joe is afraid that the system will be run on DR. I'd be afraid too.

In our proposal we suggest that there is a limited quantity that is procured that respects reliability limitations and requirements but that you can shift by shifting your forecasting, you can in fact, be more efficient and procure this product -- a summer capacity product, with the same kind of obligations and penalties as the other capacity products albeit within a shorter performance period.

And yes, it's very tough. It doesn't impact reliability and PJM has control over it, they can verify it. What else -- and it brings down, you know, customer choice, customer cost. It just -- it makes so much sense and they've done it already. It's not reinventing the wheel.

The stakeholder process is trying to -- its, its playing with how we calculate a peak load shaving because they don't want to address something that's already been done. They've already procured summer only, mechanics are there. It's a very elegant and simple way to address this rather than pushing and pulling at this product that's not -- that everybody says isn't a product to begin with.

You need to incent behavior, you want to incent demand response -- that's an environmental goal, it's what all the states want, why not recognize it as a product and use it as a tool, thank you.

MR. CAMPBELL: Thank you, Bruce Campbell of CPower. Marjorie said almost everything I was going to say and I think Bill said the rest of it earlier. So but to repeat yes, you can -- you can, you can go back to a product that is summer only. You could achieve that by as Bill suggests, recognizing the -- the reduction from summer peak capacity obligations that seasonal resources achieve in the wintertime.

Under today's capacity performance model for PJM that reduction is -- is totally recognized. It therefore results in limitation of the resource -- the resources that are, that PJM was willing to credit with performance.

MR. FIELDS: Bill Fields, Maryland People's Counsel. I don't too much left to say after Marjorie and Bruce. I think a seasonal -- putting seasonal aspect into the procurement would help the situation for the programs that I'm concerned about.

The measurement issue -- you know, I -- Bruce just talked about, I look at that from the customer's perspective and I'll repeat just a little bit about what I said before that if the customers peak load in the winter is significantly lower than the summer, then if they can bring that summer peak down there really isn't a reason.

I mean that's all you need to procure for that customer and if we set up the rules so that that can work that way then that ought to work for those customers and it ought to work for reliability. We should get enough capacity without procuring more than we need. Thank you.

MR. BOWRING: So responding directly to the question, first of all I mean I don't think that modifications of products need to be alternatives to changing the load forecast methodology. I mean clearly the load forecasting method needs changing and with all respect to the actors of the model time for 17,000 megawatts long on June 1st, 2018 clearly there's some issue with the forecasting.

Whether it's the model or something else I don't know but clearly the forecasts have been high. They've been systematically high and pretty clearly not -- not reflecting the actual market outcomes and really only high and not low.

Another -- another point in response to something I think that Bill said earlier which is that in the current system where the 1 CP allocation capacity costs -- what Bill said is absolutely true about the definition of band size. If you pay for 100 megawatts in the summer, you're paying for that year 'round. It doesn't go down in the winter, you're paying for 100 megawatts 365 days a year.

And if you're less than that and you say you're going to go down to 90 and that's your DR program and you're less than 90 in the winter, under that definition which is the current definition, you're less than 90 and being considered in order to being an annual program.

If you have a heat pump and it goes up, that's another matter but if you are actually less than your 90 year 'round, given the way that the capacity allocation is defined, Bill's absolutely correct, that's the way -- that's the way it should be thought of. But, I obviously don't agree with Marjorie and Bruce and Bill about how perfect the current DR model is. I mean let's just think about that.

Think about what it is. It is an -- it's competing with regular thermal resources which are all economic resources and demand side is considered to be an emergency resource. It's not called on economics. It doesn't have to make a must to offer in the day ahead market, in fact, measurement and verification is terrible.

It has a number of issues with portfolio, with hourly measurements. You have demand side fatigue, it's not nodal, but why in particular, would you want it to be an emergency only resource when it's competing in a market with other economic resources -- that's the question.

And that by itself makes it -- makes it not something which is a real -- a good alternative to peak shaving. A modification would be to make it truly an economic resource. That would be a great modification that would make demand side potentially work. I'm going to leave it at that, thanks.

MS. PHILIPS: So I think this is really about economics not about really the mechanics of DR because there are plenty of peaking generators that don't run all year and they're called on -- surprise, in the summer.

The fallacy that everything runs 24 by 7 is a fallacy. In CP you have an option of having gas or you have an insurance coverage for when you don't and you pay your insurance because you're not there.

Demand response is simply another tool. It doesn't look like the others but it works the same way. The point of the capacity procurement is to meet your peak load right? That's why -- that's what PJM procures to. Demand response plays an active role -- a very solid role in helping you to meet that goal.

And the point is it's supposed to be an efficiently clear market. DR is efficient, that is the problem. DR is less expensive and it brings down capacity revenues and that is something we do struggle with in PJM is everybody getting compensated?

But that's a different issue than the utility of DR in meeting the objectives of the capacity market because it certainly does and it can certainly meet it in the summer, the way we've proposed. You know, it's unfortunate wind can meet it in the winter but summer -- PJM's a summer peaking region which is why we have proposed a summer product as opposed to seasonal which you're going to get into in another panel so I'll stop there.

But I think Joe makes his point is that it doesn't belong because of economics and I think that's an important policy decision -- that we believe it does help meet the capacity procurement goals and should be considered. Thank you.

MR. FALIN: Tom Falin from PJM. I guess the scope of this discussion it's kind of gone beyond peak load shaving but just to respond I guess to some of the comments I heard. It's true -- with the implementation at capacity performance, all the resources had to be annual.

PJM heard some feedback from our DR providers particularly I did some of my own DR. So some modifications were made later -- enhanced aggregation is one of them so in an attempt to allow summer DR to continue to participate under capacity performance there's now this process where they could be paired with some wind generators for instance, in the winter who may have some capability beyond their summer output and therefore if you aggregate that it's summer only DR with wind you could span the full 12 months.

I think there's also the alternative that energy efficiency -- to offer that in, that's handled on the -- on the supply side. So the energy efficiency is actually added back into the load forecast that is used in RPM so that EE can offer in its supply.

And then, of course, there's also PRD. And just on Bill Fields comment I guess -- he had the example if my summer load is 100 megawatts and my winter load is 80, haven't I already complied in the winter just because I'm below my summer?

I think it's important to recognize that that seasonal load diversity has already been reflected in the installed reserve margin in PJM. So the fact that the RTO overall has about a 15% difference between its summer peak and its winter peak, that load diversity benefit has already been counted on in our LOLE study. So the IRM is what it is, partly because we had that seasonal diversity.

So if you would abandon that then, some recalculations would have to happen in the LOLE study and possibly the IRM could go up. So I guess I just wanted to throw in my two cents about the -- I mean PJM understands the challenges that summer only DR may have, under capacity performance, and that is why we have taken some steps now to try to, you know, facilitate their participation to some degree.

MR. RIEHL: Thank you. So the next question I'd like to ask is getting to the follow-up and Mr. Falin you touched on this, the summer DR task force that's ongoing with the PJM stakeholders. I'd like to take the temperature of the panel and if you could say on a scale of 1 to 10, 10 being highly confident, what are your hopes for this panel?

Do you think that this task force, do you think will improve the situation and why? Or just generally comment on it, thank you.

MS. PHILIPS: I'll start. I think it's -- I want to be clear. It's great that PJM's doing it but it's because they're scared to death that you might actually make them bring back summer demand again.

And so I am confident that something will come out of it in an effort to thwart any attempts to bring summer demand back into the capacity performance. Am I confident that it is as good if not superior outcome -- no. Again, for the reasons that PJM can't control, can't dispatch it and it's not going to provide the same economic incentives to have customers respond.

So thank you for asking the question. I forgot to say it's Marjorie Phillips, thank you.

MR. CAMPBELL: Thank you Bruce Campbell, with CPower. I agree with Marjorie, I think something will come out of that task force. I think that like many of the fixes that PJM has thrown trying to accommodate summer only resources is a fix that is marginal at best.

Currently about 33% of PJM's demand response derives from HVAC programs meaning basically air-conditioning, about half that is residential programs. My opinion is that residential programs are probably the prime candidate for peak shaving incorporation.

And, but as Marjorie alludes to that's going to depend on how measurable it is, how confident -- the degree of confidence that will continue from year to year and so on and so forth.

But that also leaves the other half of this seasonal peaking resource that lies with commercial and industrial resources. And those resources are typically not part of state programs. They are unpredictable. I mean I have customers who engage in both peak shaving and demand response and basically, you know, we tell them when it's maybe going to be one of these days where it's a 5 C peak day and the customer decides whether they want to curtail or not and we don't -- it's entirely up to them.

We don't tell them to do anything. We just tell them this is what's happening. And in terms of what they do, and they do what they do and it's not -- I don't believe that that sort of behavior is going to be reportable to PJM in such a way that they could act upon it.

A market monitor might believe that that's an entirely rational way to approach things, but how you incorporate the forecast, I don't know but that's a lot of megawatts. That's still several thousand megawatts of what is currently demand response being lost is as peak shaving resources.

And so I think again, I agree that there will be something coming out of that. What will actually be gained in terms of retaining summer only resources -- I'm very skeptical it will be substantive.

MR. FALIN: Tom Falin from PJM. I'm the optimist on the group I guess. I've been to a lot of those -- I guess this task force has been meeting since December of last year so we've had four or five meetings. I think a whole lot of education has gone on at that task force.

I think folks understand better now just curtailing on the 10 CP days of each summer is not the most strategic way to impact the load forecast and I think it's actually at the point now where all the stakeholder interests have been captured. We're in the process now of the design components -- what should the solution look like?

I mean certainly a goal of PJM -- we're interested in having as accurate a load forecast as we can. I mean even outside of RPM, we want to get the forecast as close to accurate as we can. So if there is indeed a fundamental change in peak shaving behavior we need to capture that proactively.

So I think, you know, so PJM is committed to doing that. I think the stakeholders understand kind of what the drivers are. You know one possible outcome could be -- as long as we come up with some sort of future commitment to peak load shave under some conditions, for some duration over some monthly period, then perhaps PJM could do a technical study to see what the actual impact on the load forecast would be.

As I've already explained, because of the intra-day load shifting and the interrupting based on weather rather than peak load level it's unlikely to be exactly one-for-one. Its impact on the load forecast but I could see some kind of, you know, solutions coming out of that where we perform some analysis that justifies once we produce a load forecast in the future, we should then have a discreet adjustment downward to recognize that future peak shaving behavior.

So I think something good will come out of it. I know the timeline I think is to get back to the more senior committees by the end of this year and hopefully file something with FERC in early 2019.

MR. FIELDS: Bill Fields with Maryland People's Counsel. I guess I've heard some -- some good news and bad news as it's come down the line towards me. The residential programs that I'm particularly concerned about -- our customers participate in -- seem like they do fit a little better for some of the discussion that's happened in the working group as far as identifying and relying on the load reductions so that's a positive discussion that's going on.

It's a long way to go to figure out if there's really going to be something that gets sufficient support to go through. We're also concerned about the issues that Marjorie and Bruce raise with other types of resources in making sure that that value is captured as well.

MR. BOWRING: So I'm a bit skeptical about what's going to come out of the task force. One -- hopefully, I mean it's forecasting improvements would be great if that happened and the ability to actually incorporate on the forecast the actual peak shaving behavior in closely real time would be a very good thing.

I'm not sure that's exactly where the Committee is headed. One of the points about forecasts and there's been criticism about relying on the impact of forecasts -- of peak shaving forecasts and that being a reason not to do a peak shaving.

If you think about it, think about adding something back to the forecast. So you don't like the forecast and then you're taking an add back which is based on pre-assessed backed M&V and adding it back to that, how is that better, how is that more accurate? How is that more consistent with an efficient market than letting people peak shave and actually drive down the price of their own activity by reducing demand and having it reflected in a forecast.

So I don't think those issues are all being addressed fully in the task force. I don't think the question of the allocation of capacity costs and the impact on what DR actually means is being addressed in the task force. I don't think that the fact that a summer only product has been tried in PJM.

We've demonstrated that it's suppressed the price to the tune of billions of dollars in the capacity market. I don't think that's being addressed in the task force. But lest I sound like I'm anti DR which some have accused me of being, I think DR is a critical part of markets. No market works on only the supply side. You have to have a demand side.

You have to have a vibrant demand side, but to me the vibrant demand side is demand side which is reacting to price and then affecting the market through the forecast of the demand through the price, not through the convoluted rules that are required to be a non-economic resource, adding things back and all the other things that are part of -- part of the CP way that demands that.

MR. RIEHL: Thank you, Mr. Campbell and his folks?

MR. CAMPBELL: Yeah thank you, Bruce Campbell with CPower. Just one follow-up comment about peak shaving in general versus a demand response product and that is that peak shaving is much more costly than demand response resources for customers.

That is because they must curtail their load more frequently. They curtail it several times every season versus perhaps just a test for demand response product or, you know, in potentially many events for a demand response product but we haven't seen that.

But it's very true that as long as you're peak shaving, you're peak shaving for multiple times each year and each peak shave for each customer is costly and when it costs the customer more they're going to be less inclined to participate.

MS. PHILIPS: Marjorie Philips, so I just wanted to point out one thing too and it's a little off tangent, but you know the point of being here and advocating for the summer demand has to do with switching how you forecast in LOLE which is, we know, future panels are going to talk about and hopefully it makes sense some of the things that I'm saying now.

We're trying to -- we are looking out for consumers. And we are looking, trying to get an efficient price to them. As Joe mentioned, PJM's forecast procurement is wildly off. Consumers are paying billions of dollars for capacity that is unneeded. And if you switch some of the load forecasting and recognize that PJM is peaking, if you used a summer DR product it would in fact, reduce the amount of capacity procured and would in fact translate into benefits for customers.

When you talk about peak shaving and units going off and saving money -- that drops the energy price right? And when the energy price drops guess what happens -- the capacity price goes up. So there is an overall connection with all of this that is way beyond this panel's discussion.

But in PJM nothing works in isolation so it's really important to look when you're looking at overall costs, what's the impact of the capacity market and how does it relate to the energy market because that's what the customers are paying for, thank you.

MR. BOWRING: So in response to Bruce I would say precisely. That's the point. Peak shaving is a product -- you actually have to do something. You actually have to change your measured load, you don't simply get paid for being an emergency resource that never gets called on -- that is precisely the point. It's a market response, it's real, it's measurable and that's the point.

So it's not surprising that it costs more to do that because you're actually doing something. You're actually responding to price, you're actually reducing your load, you're actually having a real impact on the market. And when the capacity price goes down the energy price does not go up Marjorie, so you know, so it's possible to have the capacity price be suppressed and not have that be off-set on the energy market.

And conversely, when the energy price goes down under CP -- that does not change the offer cap in the capacity market and the notion that it is an automatic upset of capacity -- of capacity prices when energy prices go up is not correct under CP.

MR. FIELDS: Thank you, Bill Fields, Maryland People's Counsel. I think the nature of capacity markets -- capacity obligation is sometimes there's resources that get paid that don't, you know, have to do anything all year.

That can happen with generators and if that happens with DR that should be sort of a disqualifying thing.

As far as the DR that we've had and whether it's suppressing price, I think it's more that you know, if we made customers buy even more beyond what they really need, yeah, prices would be higher but you know, reflecting the DR I think reflects the ability of customers to say well we don't need -- going back to my example, we don't need that 100, we only need the 90.

I don't look at that as price suppression. I think that's reflecting, you know, the fact that customers need less and there's competition to supply what there is and that results -- hopefully results in lower costs for customers.

MR. MONICK: A follow-up for Mr. Fields. I wanted, if you could respond to comments that were filed by AEMA, they made a point at the end of their comments that one of the drawbacks to incorporating state programs in a peak shaving forecast is that states may reduce their use of those programs or they can cut the support for them, so they may not be able to over the long-term count on those programs, any response to that?

MR. FIELDS: Yes, I think, well it's a legitimate point in that going back to what I was saying before. If there's not value reflected in the wholesale market they may very well decide not to keep doing it. I think that's certainly a possibility.

But so I think it shouldn't be -- the answer shouldn't be that because there's been some peak shaving this year that we're going to change the load forecast necessarily that exact amount, and assume it's going to be there going forward. The programs I'm talking about I think we are okay with the idea that there is some commitment there, there are some requirements out into the future -- at least that three years we're talking, you know, that three or four procurement.

That there are some requirements, there are some possible penalties. You know, that's the world we've dealt with with these programs in the past and I think we could do it again. Obviously it gets more complicated when you get talking about some of the other types of peak shaving efforts.

MR. RIEHL: So one additional question I would try -- one additional question that both Mr. Campbell and Mr. Falin touched on. Mr. Campbell you said that you have customers that are both DR and do practice peak shaving. And Mr. Falin you said that during the summer DR task force there's been a great deal of education so far. And I assume and I believe you touched on it that some of that educational activity is related to the temperature humidity index, the THI figure.

So I was wondering if you could both or -- and the larger panel as well could touch on or elaborate on how to, you know, when there's information sharing with the people who are practicing peak shaving, what kind of signals they are sent and what would be the advantages, disadvantages of better incorporating the THI into that kind of information to incent that activity -- I hope that made sense, thank you.

MR. CAMPBELL: Thank you, Bruce Campbell with CPower. Again, we have customers that peak shave and they have been peak shaving for years and I think perhaps pre-dating RPM. So from their perspective just to maintain the status quo they need to continue to do that.

They also -- but you know, what they're getting is, you know, we project where the 5 CP days are that establish their capacity obligation. We say this is a likely 5 CP day and they will cut their, user commercial and industrial customers, they'll look at what's going on that day and say I'm going to curtail or I'm not going to curtail.

The question becomes from a -- and how you incorporate that into a forecast I don't know. If you -- I feel you can't require customers to act unless you're going to compensate them directly for it. And as Dr. Bowring points out, if they're curtailing, they're going to get the benefit of a reduced capacity obligation in the first place.

But they want the flexibility to do this when they want to do it and when they can do it, they're looking at their costs of production, they're looking at what's going to happen if they do peak shave or if they don't, they'll take their chances that maybe it's going to be a hotter day later in the summer.

It's kind of all over the place. There is a set of -- of, there is a separate set, however, and in Pennsylvania for example, there's an Act 129 which is -- incorporates a state-wide peak use reduction program, a state program, and we have customers that participate in that triggered on a 96% of PJM forecasting quote.

I don't know how that would be incorporated into a PJM forecast. I'm sure PJM will be looking at that to see how they might incorporate that, but that hasn't got the stakeholder process, we haven't gotten to that discussion.

One comment I would make about that program is it was in place for one year in 2012, suspended for a couple of years and then began -- it was in place again last summer and we expect it to be available for the next four summers.

After that, no one knows. I don't know. I don't think -- I don't think anybody here at the table knows. So you have some concerns about that in terms of how you make a forecast. So that's kind of my look at it and again, that's one state. We don't see any signs that there are similar problems with other states which means that resources in those regions aren't captured by these kinds of forecasts.

And I believe that you really can't incorporate this stuff into the peak shaving into a forecast unless it's part of some sort of a state-sponsored program that has real required reporting.

MR. GOLDENBERG: Mr. Campbell, I have a follow-up question. If an industrial customer is deciding sort of on the spur of the moment, you know, they're not planning for these reductions, why don't they bid into the market as an economic demand response resource instead of in the capacity market?

MR. CAMPBELL: Because it gets added back. If they do an economic demand -- an economic activity on one of these 5 CP days, the load reduction that occurs on that would get added back into their load, so they wouldn't achieve their result which is a lower capacity obligation.

MR. GOLDENBERG: Right, they would get paid in the energy market for their reduction wouldn't they?

MR. CAMPBELL: They would get paid in the energy market, but the capacity component would be -- is likely to be much higher value. So it wouldn't -- I mean you could measure it of course, against -- and beyond that the economic baselines are different than the capacity baselines.

But the real issue becomes if they happen to do a peak shaving on a day that is designated as a 5 CP day and you don't know until October or after the summer which of those day there are so when our customers peak shave, they're not doing economics because that -- that doesn't achieve the desired result because again, it gets added back to the -- the curtailed amount gets added back and then counted as part of their peak capacity demand for that summer.

MR. GOLDENBERG: So would you suggest that PJM not add back economic demand response but only add back capacity demand response?

MR. CAMPBELL: That could be fixed. I don't know the -- I will say that in our experience in recent years, certainly the energy revenues from participation are not substantive. That's part because Marjorie was to the, you know, lots of excess capacity means lower capacity, and lower energy prices.

And many of our customers don't -- aren't economic participants either, perhaps 20% at most. I think it's more like 15% of our customers do economic demand response, the rest are just strictly capacity only.

MS. PHILIPS: Marjorie Philips. I think the problem too, if I were PJM I wouldn't want to add it back. I don't know if they're going to have the same behavior next year. There's no predictability. There's no ability to dispatch it. There's no ability to penalize. So why would you give a customer participating who just peak shaves without any kind of obligation -- it doesn't seem, from a PJM perspective, the problem is are you really going to want to count on them and I suspect the answer is no because you don't know if they're going to behave the same way next year.

MR. FALIN: Tom Falin from PJM. I agree with Marjorie completely on that. The whole rationale as to why an economic demand response needs to be added back is because it's not a committed resource okay? It's at the decision of the end use customer and who knows what the future behavior of that customer will be?

So I think in terms of planning the system and in procuring capacity, that's kind of an action that PJM is not going to want to count on in the future.

Regarding your earlier question about sharing data and transparency, certainly yeah, PJM would be, you know, interested in furnishing as much data as we can. I think the motivation of curtailment service providers to peak load shave really depends on what kind of CSP they are.

If they're not affiliated with the EDC then their incentive actually is just to try to hit the 5 CP days of the year -- the top 5 RTO peak days of the year. And the reason for that is because the EDC in that zone will take the PJM load forecast and then allocate it to all the various customers based on their share of the 5 CP.

However, if you're a curtailment service provider, you know, affiliated with the EDC, the motivation I think is to actually reduce the zonal load forecast. So as we talked about kind of the most effective way to do that is to really target the hot days, not necessarily the high load days, and to also realize that you could have that peak shaving.

So I think PJM would certainly be -- in fact I think we've kind of reviewed some linear regressions with the senior task force about what kind of temperature humidity threshold kind of enters into the far right part of that curve.

And if you were to hit, you know, curtail at that temperature, humidity index or higher, your impact on the load for RTS would be much greater. So that's certainly the kind of data that we could, you know, share with folks on a zonal basis.

MR. BOWRING: So one of the points about peak shaving is it also has a big effect on transmission distribution costs because the billing determinants are typically similar -- 5 CP or 1 CP. So regardless of the wholesale power costs you're still saving on the other two-thirds of your bill in a very significant way.

So peak shaving -- peak shaving makes sense. I'm assuming that's part of the reason customers continue to do it even on top of DR programs. Peak shaving has its own separate non-wholesale market reasons for existence in addition to its impact on the wholesale market.

I agree with Bruce that when you're peak shaving you have a lot more flexibility. That's the point. You respond to a market in a flexible way. I think that PJM could provide more information to customers. I think Tom started going down that path and I think weather forecasts are already provided, THI forecasts better information about what PJM expects peaking days and hours so that customers can actually respond to that.

And part of the answer to your question about offering not economic -- I mean first of all as Bruce pointed out about 1% of all DR revenues from the economic program in recent years and even in prior years when prices were higher it wasn't a whole lot more than that -- it never got above 5 or 10% but it's been very low.

And there's really no reason to offer an economic if you're responding to the price, by reducing your purchases, then you save the LNP, and then you don't have to worry about the add back.

And finally, of course all customers' behavior is somewhat hard to predict. There are 60 million customers, of course you can't predict them all and you can't require that they're going to behave in a certain way. And the idea that DR can only work if you know what each customer is going to do on a particular day is kind of odd.

In a market, I mean that's -- that's the kind of uncertainty you have to deal with. That's what you want. You want customers having the individual flexibility to respond to the price incentives, that's what markets are all about -- not requiring them to do a particular thing on a particular day -- in the case of DR, not requiring them to do anything almost all of the time.

MR. GOLDENBERG: But isn't the devil in the details because the argument by the other four people or the other three is you are not reflecting that in the way you're forecasting the loads? The uncertainty is not being reflected just with respect to my question about adding back economic DR.

Well we can't count on it. Well if you can't count on it you can't count on it for anything can you?

MR. BOWRING: I think you can. I mean it depends on what you mean by counting on it. If people do peak shaving and reduce their demand that should show up in the forecast and I agree that it's very significant problems but those can be resolved.

It should be reflected in the forecasts, there should be an immediate feedback to those customers who are doing peak shaving to make sure that it is affecting the forecast. But when you are adding something back you're just adding it back to a forecast, that's no more certain than the line on the market response.

MR. MONICK: Marjorie, real quick and then we've got one more question.

MS. PHILIPS: Marjorie Philips, real quick I just have to respond to Joe and go back to the purpose of the capacity market right? It's to call on resources when we are in a peak critical reliability. That's why we have peakers that are allowed to participate. Why wouldn't you want to incent a resource which demand response is -- it's a different looking one, but it's a resource.

Why wouldn't you want to incent them, have them have obligations and so they can contribute when you are about to go into this crisis? At the end of the day you can have all your generation running and maybe you need a peak run. Wouldn't it be great to be able to initiate a demand response and that's the point of this.

It's not you need capacity all year 'round, but this particular procurement is geared for managing peak loads.

MR. PHILIPS: Yeah just real quickly, the purpose of the capacity market is to make the energy market work period. And this does not -- what Marjorie has described is not really helping. CT's are not emergency only resources. They are resources that are available whenever there's a peak.

MR. KATHAN: I want to focus on one area. I think we've talked about a third question on the topic which is -- does seasonal nature of most customer peak shaving efforts negatively impact the ability to provide demand response? And, you know, list several things including price response and demand -- now there is a price response and demand program in PJM in which, you know, reflects upon a number of things that Marjorie was just talking about which is it is -- you bid in, it's expected, and it provides capacity.

It wasn't used for many years until the past summer when it was 500 megawatts did clear, you know, in the capacity market but my understanding is that that was a seasonal product that cleared. It was, you know, the peak time rebid I believe coming out of the Maryland programs.

So the question is what is the prognosis? If that was a seasonal product and the CP, you know, is the way that PJM is counting capacity -- what is the plan? Is this

PRD -- I know it was brought up at the stakeholder discussion, a change on that -- what is the future of PRD?

Is it being discussed in the task force? What is the view of the panel, especially PJM?

MR. FALIN: Sure, Tom Falin from PJM. My understanding is and I'm not involved in a lot of the markets stakeholder meetings, is that the proposed change to PRD is actually on hold pending the outcome of this other summer only demand response task force.

So I think that there was a proposed change on the -- on the, you know, on the part of PJM regarding what Bill Fields sort of alluded to that any kind of a load reduction in the summer has to also occur in the winter.

So that is a change that PJM had proposed. As I recall it went to a markets and reliability committee meeting, it was scheduled for a vote but at that point the vote was deferred. So I think the reason for that was to see, you know, what the outcome of this other task force is since it's sort of addressing the same kind of issue -- how do you handle load curtailment that, that can happen only in the summer?

MR. FIELDS: I don't have too much -- this is Bill Fields with Maryland People's Counsel. I don't have too much more to add to what Tom said. That was the issue of the measurement of the reduction -- is it against your annual peak load or is it against that winter peak load?

If that rule were changed, then I don't think that the PRD that we've seen would be able to continue and then we'd get back into this well is it just peak shaving and when does it get reflected?

You know, if there's another way that comes out of the task force besides PRD to reflect that value in the market someway, you know that would be great but certainly it is our concern that if you change that rule that that PRD is going to go away, that value is going to go away and that's going to endanger the whole reason for doing it.

MR. BOWRING: So I mean the PRD program morphed a great deal from its original proposal. And the way I thought of the original proposal was a compromise between what I've been saying and what Marjorie's been saying for example which is that it would be outside the market, but people would commit to doing it.

So PJM would reflect it in the forecast, reflect it in its demand but it could be counted on and there would actually be a commitment to do it and I still think that's a very good idea. I think the PRD program has morphed so far away from that it doesn't look like the original proposal but there are ways to compromise along those lines that would make DR effective, reliable and not have to depend on the details of the capacity performance rules in order to participate.

MR. KATHAN: What would be those, you know, changes that you would recommend?

MR. BOWRING: Just I mean basically to go back to the original design which they haven't been not directly participating in the capacity market but being a commitment to reduce load under defined conditions and PJM would not account for explicitly in its forecast and it would be paid immediately as a result of reductions in load.

MR. MONICK: Thanks everyone again for your time, your expertise. We're going to take a quick break, 15 minutes and we'll be back for the next panel, thank you.

(Whereupon a brief recess was taken, to reconvene this same day.)

MR. MONICK: If everybody could be seated we're going to get started. Thank you, welcome back everyone. Thanks again to everybody for joining us. We have a new staff member joining us if you could introduce yourself.

MR. COHEN: I am Tristan Cohen, OEMR East.

MR. MONICK: I would like to welcome the panelists for our second panel which will cover Loss of Load Expectation. We have with us today Michael Cocco from Old Dominion Electric Cooperative, welcome; Tom Rutigliano from Advanced Energy Management Alliance; Tom Falin again from PJM; Michael Jacobs, from the Union of Concerned Scientists and Joe Bowring again from -- the Market Monitor for PJM.

Thank you to our panelists for joining us. I'm sure you guys know the drill by now but just to remind everyone to turn up your tent cards if you're interested in speaking and remember to turn your microphones on while speaking and off when finished.

This panel will run until approximately 12:30 and then we'll have our one hour break for lunch before the last panel. This time we'll get started I'm going to introduce my colleague Dave Mead who is going to have the first question for the panelists.

MR. MEAD: Thanks David Mead in the Policy Office. I have a question that I'd like to post first to Tom Falin and then others can join in as they see fit. As I understand it the complainants argue in this set of proceedings that when procured annual capacity is at the target level, the loss of load expectation in the ten summer weeks is virtually 0.1 and that the loss of load expectation for the remaining 42 weeks is virtually zero.

And they argue that the PJM-wide .1 LOLE could be maintained by increasing capacity modestly during the summer weeks while reducing capacity by a greater amount procured in the non-summer months. And as I understand it this conclusion is based on the results of a study that PJM presented to the stakeholders.

But PJM has remarked that those results were based on assumptions that perhaps are not the best and if you made more realistic assumptions, you'd get a different distribution of LOLE and in particular you would get at least some positive LOLO in the non-summer months or summer weeks.

So I have two questions. One is by using more reasonable assumptions, what would be the loss of a led expectation in the summer weeks -- the non-summer weeks and overall and in particular is the LOLE in the summer still higher than in the rest of the year and if so, could the distribution of LOLE's be between the seasons be changed so that you continue to maintain the PJM-wide 0.1 LOLE but you had a different distribution of LOLE's between the summer and the non-summer.

Long question but --

MR. FALIN: Okay thanks, Tom Falin from PJM. There's a whole lot in your question there but I guess reading a lot of the comments that have come in for this Conference I think there may be a misconception out there that PJM somehow allocates the LOLE between seasons in our installed reserved margin study.

That's not the case. The fact is that PJM is a very pronounced summer peaking region. I think our summer load might be 150,000 or so compared to 130,000 in the winter. So the fact that our model comes back to say the LOLE seasonal allocation is essentially 100 and zero is sort of a natural consequence of our monthly load profile.

It's not PJM's intent to pick and choose where the risk should go. So that is the result of our model and it's essentially because when we solve for the amount of capacity that PJM needs, that's assumed to be a horizontal fixed megawatt amount every day of the year.

So in the case of PJM I think it's about 175,000 megawatts of installed capacity every day of the year. Now that approach I think is a very common practice in the industry, in fact, I'm not sure there's an RTO ISO that performs LOLO studies that does not make that same assumption that it's a constant amount of capacity in terms of megawatts, not reserved margin because you'll be expressing it as a different seasonal load, but it's a fixed megawatt capacity that's procured.

So the initial 100 zero allocation again is completely dependent on our load profile, it's not that PJM seeks that allocation. Now in a lot of the studies that you cited, it's true at the request of stakeholders we were asked what happens if you were to go from 100 zero to 90/10, 80/20, 70/30? So that's certainly something that mechanically can be done in our model before we did it though we had to make, you know, a slight change to our model.

After the polar vortex events I guess in January of 2014 when we saw one day had a 22% forced outage rate -- if you look at our original LOLE model, it just assumed -- it takes a distribution of forced outages so the average is around 7-8% and then it comes up with the chance of having higher or lower than that and our curve didn't go beyond 12 or 13%.

So at that time, according to our model, there was no chance that we'd ever see 22%. The fact is we did see it that day so we recognized that shortcoming in the models so there had to be -- the basic reason was our assumption had been that all forced outage rates are mutually independent.

The generators forced outages are uncorrelated. Well we, of course, back in the polar vortex, you had strongly correlated outages. The gas pipelines were unavailable, every station, every unit would be unavailable.

So after we made that change to recognize the risk, particularly during the winter peak week of these concurrent forced outages, we then ran those various scenarios that you talked about. And true, the numbers came out as we presented at stakeholder meetings.

The other challenge we had I think in the winter to try to capture more accurately was how the generator maintenance schedule would work. Right now our model simply receives an input that each generator requires "X" number of weeks of maintenance each year.

So the user does not specify the calendar placement of that maintenance. Instead it says each unit requires "X" amount of maintenance and our model is going to optimize where to place that maintenance okay?

So our model clearly has perfect foresight. We feed it a weekly load model so it knows exactly what the load is going to look like so it's really able to optimize where to place the maintenance to have a minimal impact on LOLE.

PJM operation's obviously does not have that luxury. A request for maintenance may come in in September for the upcoming winter and they have to decide whether to grant it or not, you know, not knowing where the day of the actual winter peak.

So we also made some modifications to the model to assume I think the average amount of generator maintenance on the winter peak week. I think over a 10 year period. So when we made those adjustments and then produced those runs, you're exactly right it shows things like okay if you were to increase the summer reserve margin by say 500 megawatts, that would obviously reduce the risk in the summer therefore you can accommodate more risk in the winter and as a result the reserve margin in the winter would come down by a few thousand megawatts.

So all that I think is just based on the technical assumptions but to, you know, to intentionally distribute the LOLE risk in some arbitrary manner, you know, is not a common practice in the industry. I think it would have a lot of implications obviously on capacity prices.

So in terms of the facts and the results of our study I would agree LOLE is kind of additive throughout the year. So if you were to consciously decrease in one season you could increase it in the other.

So yes, so our results are what they are. I think there are some further refinements -- the reason we label them as preliminary results is we're still working on the winter load forecast model. A lot of the focus has naturally been on our summer forecast model because that's usually -- that is the basis of the LPM charges, but now we've turned our attention to the winter load model.

Obviously, now we've had several winters in a row where the load variability has been quite large in the winter. So, I wouldn't take those numbers to the bank because we're still working on trying to capture that winter load forecast error better.

MR. MEAD: Okay thanks, so just before I hear other people. Did I hear you say that when you make the adjustment for different assumptions like for example, outages are coordinated and not independent, you find some positive LOLE in the wintertime but that LOLE is still smaller than in the summer months?

MR. FALIN: It is correct. Right, and once we model those concurrent outages in the winter what we learned is that those 30% ICAP reserves in the winter that you need that to be at one day in ten. I mean if you were actually to keep the summer megawatt requirement where it was but remove 1,000 megawatts of capacity in the winter, we would then no longer be at one day in ten, yeah.

MR. MEAN: Thank you, why don't we start with Mr. Cocco?

MR. COCCO: Good morning. I'm Michael Cocco and I'm with Old Dominion electric cooperative. First I'd like to thank the Commission staff for hosting this Technical Conference in response to various 206 complaints that were challenging the need of all capacity resources had to be annual capacity resources.

As this staff knows ODAC was one of the complainants in this proceeding, filed pre-Technical Conference comments and as I answer your question I'd also like to maybe touch on some of those earlier remarks.

First, I generally agree with what Tom said but there was a lot of information there so I kind of just want to take a half step back and maybe regurgitate a little bit of that. In the Commission's earlier order one of the questions they asked is it true that the loss of load probability is contained in 10 summer weeks?

So just in the way of background, the prison model that PJM uses to calculate the loss of load probability is based on a 52 week model. So what the program does -- it calculates the loss of load probability for each of these individual weeks sums them up and the determined annual loss of load expectation.

Now this program is used for the established internal reserved margins starting or the IRM studies as PJM refers it too. At one day in ten reserve level while every week may have some infinitesimal amount of loss of load expectation, any measurable amount of loss of load probability is contained in that study in actually six summer weeks -- and that's out to four decimal places.

Now in reading some of the pre-Technical Conference comments from others they responded to this question a little differently than I did by stating that if you reduced the amount of winter capacity by even 1 megawatt, the reliability index would fall below 1 in 10 and while it's a true statement I just don't want -- I don't want the Commission to infer that there is sizable loss of load probability or the same size of loss of load probability in the wintertime.

In that hypothetical example that I just described -- yes, the LOLE would drop below 1 in 10 but it would be 1 in 9.999. So I believe this first conclusion is an important one that under the established methodologies and for all practical purposes and the operative word here is practical -- the entirety of the loss of load expectation is contained in just a handful of summer weeks.

And I'm emphasizing this point just to avoid any confusion on the part of the Commission as it's trying to gain like a meaningful understanding of the loss of load expectation methodology.

The second point that I would like to make is having as Tom indicated and to your question suggests is -- is having all the loss of load probability -- having all the loss of load expectation in the summer weeks is not a stated reliability goal.

It's really just an outcome of the model that has a significantly higher summer peak and a requirement that all capacity be fixed over that entire year. Now I don't want to get too far ahead but as you are going to hear from latter groups, they're not going to be recommending that we target a specific seasonable distribution -- loss of load expectation distribution, but whether we have a range of allowable parameters and let the eligible supply side resources solve those economically to achieve some loss of load expectation distribution that maybe something other than 100 to zero.

So not targeting the loss of load expectation, but allowing the model to optimize resources to reduce customer costs. And so I'm not going to -- I don't want to expand too much on those proposals at this point but I do want to more fully describe the seasonal trade-off analysis that Tom mentioned earlier.

And for this purpose again as Tom indicated, they did not use the prism model but used another tool that had the capability of looking at avenues that were not uniform. So we're just going to describe in one of those cases -- instead of meeting the 1 in 10 reliability target with a fixed amount of capacity throughout the entire year, it -- they determined that by reducing the summer peak, their summer capacity obligation by 1,461 megawatts -- I'm sorry, by increasing the summer capacity by 1,461 megawatts you could reduce the winter peak by 6,172 megawatts.

Now there's a whole bunch of different assumptions that went into each of these scenarios. The particular scenario that I am describing assumed that there were no planned outages allowed in the winter weeks -- peak weeks, but since we do in summer time and that we used for established data from the 2515 polar vortex.

And this is going to be a discussion that's probably going to transcend all of these panels from this point on. I think it's appropriate to use the 2015 polar vortex data because that is after the CP rules went into effect requiring a whole bunch of changes to capacity resource.

I think the counter-argument that we should be using the 2014 polar vortex data -- before there were these capacity performance rules that were intended to improve generator performance is simply inconsistent. So I think there are significant opportunities then for holders of supply-side resources to participate in these markets but because of this trade-off analysis you just -- I just described, so thank you for my first comments.

MR. MEAD: Mr. -- I'm sorry, yeah, you there. Could you pronounce your last name so I can try better next time?

MR. RUTIGLIANO: Thank you, yeah, Tom Rutigliano for the Advanced Energy Management Alliance. And yes, first I'd like to thank the Commission for having this Conference and for inviting AEMA to present.

So certainly Mr. Falin's right in his, you know, discussion of how we're constantly improving forecasting reliability study models but I don't think those should obscure the basic fact that since PJM is a system with very distinct seasonal peaks, attempting to meet that through as flat procurement in the same amount of capacity -- all twelve months of the year, essentially guarantees a cost inefficient outcome.

You know you're essentially trying to fit a curve with a straight line and there -- with that model there's no way to avoid vastly over procuring capacity in some parts of the year just to have a barely adequate amount of capacity in other parts of the year.

It's also worth noting that most of the improvements to the reliability sense that we're talking about have been on the modeling generation side and this may be more appropriate to go in deeper in another panel but it's worth noting that the extent that we modify how we consider generation availability in forecasting, without corresponding or changing our generators as individual supply resources are rated -- we're subverting the paper performance, you know, foundation of capacity performance.

Tom also mentioned that, you know, there are no other RTO's that he knows that does this and you know, I won't disagree with him on that. But I'll just point out that as precedent PJM's capacity market has been essentially annual plus summer for many years so there's plenty of experience in how to determine a seasonal risk allocation -- that's been the rules of RPM since 2006 or so.

And then finally there's a little bit of concern about would anything other than putting all the risk in the summer be arbitrary? And again, as we'll probably talk about more in other panels and the whole point is to get this to be something that's not arbitrary and I would submit that the current allocation, you know, even if it's a product of the market rules ends up being arbitrary -- and our ideal goal would be to get to a risk allocation is driven by cost efficiency and then therefore is not arbitrary.

MR. JACOBS: Thank you, its Michael Jacobs, Union of Concerned Scientists. I also want to thank the Commission, the Staff for holding this event and allowing me to speak. So I want to turn our attention to an area that really hasn't been discussed at this point but gets to the heart of the assumptions, really to the heart of the assumptions.

As Mr. Falin just said, the assumption is that there's a procurement that's flat across the year, but the transmission system capabilities to absorb, as say essentially the injection or the interconnection rights of all the generators are established on summer conditions test.

When you do your interconnection work you get a summertime load and the system is modeled for summertime conditions. In winter obviously the loads are lower and the assumption is that all the generators that have capacity obligations will be able to make as we say in the performance assessment areas, they'll have to perform at their -- at their capacity obligations.

But the transmission system won't absorb all that, it simply has not got the load to absorb all that. So this may seem obvious but the part about what can you actually deliver in winter from the generation that you procured for year 'round, to my understanding -- I've been doing this for a while, is that it's never been tested.

So what we have is all the generation expected to perform. The transmission system hasn't been studied or built for that wintertime performance and the great irony is that this repeats the mistake made assuming the gas pipeline system was adequate to meet all the generation obligations in the winter conditions.

So with that hanging over us, there's other things about seasonal differences but that one is so fundamental to the assumptions about these models that the question of how much did you really procure that can be delivered in winter is simply not yet known.

MR. MONICK: Can I interrupt real quick?

MR. JACOBS: Absolutely.

MR. MONICK: Can you explain to a lawyer

technically why that concern exists over winter not being able --

MR. JACOBS: Sure, so there's two parts to this so if you -- just to use an analogy of automobiles and driveways and roadways so maybe I shouldn't use an analogy because I haven't prepared for that. I often use that -- I work through a lot of capacity issues.

You can put the car in the driveway and use it later but in this situation so what we've done is to make sure all the generation can be delivered to load we have a number of very specific measures that use the summer system conditions. So when you put power into the transmission system for lack of a better analogy the electrons flow somewhere.

And the transmission system works because you have the capability of delivering or transferring to some distant place -- but wherever there is load, the electrons are absorbed. So when you have lower loads you simply don't have enough places for all the generation to go simultaneously.

In summer you do -- I mean that's what we test for, that's what we study for -- the loads are higher so there's roughly 20,000 megawatts more places for electrons to go. So what we've asked in the -- in the sort of whole capacity performance framework is that the generation that's committed will perform in winter just as it would in summer.

So physically the generators are the ones who qualify and perform aren't capable themselves of the transmission system to which they're attached to which they need to get to load has been built for summer conditions which includes the benefit of having loads, you know, sort of all along the way, absorbing electrons.

A lower level of load absorbing electrons ultimately means a lower level of generation that can run without overheating the wires. So the assumption that we've procured the same level, we have in terms of paying generators, but we haven't in terms of making them pay the transmission upgrades to make themselves deliverable in the winter.

And when we go through all of these analyses of expectations we don't have all the generators able to run at their capacity obligations in the wintertime. The transmission system doesn't or hasn't been shown.

So I don't know yes or no. I just know when we talk about this in the stakeholder process when we talked about it for the winter capacity interconnection rights for wind the question was raised well we haven't really done this and so we remain with all these expectations about lost load, serving and performance with this gaff of well does it actually work?

MR. MONICK: Thank you, Mr. Bowring?

MR. BOWRING: So actually does it make sense, Tom, just to respond to that particular point because it was a somewhat unexpected point.

MR. FALIN: Sure, Tom Falin from PJM. There is a peak load winter test that we do. It's known as CETO CETL which stands for capacity emergency transfer objective and capacity emergency transfer limit. So what we do under peak winter conditions is we carve PJM up into certain sub areas and then we will test -- given that sub area and the amount of installed reserves it has internally, how much -- how many megawatts of emergency import would it need under winter conditions to satisfy reliability criteria.

So that would be the import objective. We then compare that to a load flow study that's done that actually computes what the transmission import limit is and if your transport input limit exceeds your objective, obviously then you are reliable under winter conditions.

So that is a winter -- on the load deliverability test that we have done for a while now. So I think in terms of reliability PJM planning does test the winter conditions to make sure that we are reliable. However, the other side of that is generator deliverability. That just tests if given a certain generator does it have the ability to inject system up to the bulk grid which could then be used to serve load throughout the RTO.

That is something that we started doing for wind units just about a year ago -- I guess with enhanced aggregation under RPM where summer only resources could aggregate with some wind units whose -- whose winter output exceeds their summer output.

So in the case of wind we have done a generator deliverability test in the winter. However, for all the other non-wind units that kind of test has not been done so we haven't certified deliverability of winter units at any rating above their summer rating. That check has not been done.

But in terms of reliability we do perform the load deliverability test it's called to make sure that even under peak winter conditions there are no load pockets within PJM that are unreliable.

MR. MEAD: Can I follow-up a little bit. Let me just see if I understand it. Mr. Jacobs, I think were you making the point that the transmission system in the wintertime is not capable of delivering as much energy as in the summertime?

MR. JACOBS: Mr. Mead, yes, I think that's a good summary and I'll concede that I've always looked at this from a generator's perspective. So I think there's consistency essentially with what Tom and I are saying about how far this has gone, how far it has not gone.

MR. MEAD: And Mr. Falin, do you agree with that conclusion?

MR. FALIN: I think so. I'm not sure exactly what Mike Jacobs was driving at but I guess I've always viewed it from a reliability perspective and we definitely do a peak winter test for reliability. However, when it comes to generator deliverability I know there have been some proposals made -- I think it will come up in your afternoon panel that well if some thermal units have a winter output rating that exceeds there in the summer, could they offer that in in the winter?

I just wanted to put up the caution that if you walk down that path, you know, capacity interconnection rights for the winter would have to be studied and PJM would need to certify deliverability of those excess megawatts in the winter from each of those generators.

MR. MEAD: Before Mary gets a train of thought -- if I could just ask one more question. So the implications for that may we infer then that even though PJM has an annual capacity market construct that as a practical matter the amount of capacity that's procured for the summertime -- not all of that is available to be used in the wintertime -- in the wintertime, is that a correct inference?

MR. JACOBS: So I would say that's a correct inference.

MR. FALIN: Okay I would not. Right -- what I'm talking about is the winter -- the winter rating that is higher than the summer rating. I think the fact that we again perform this winter reliability test tells us that the system in the aggregate, the load can be served at the specified reliability criteria.

MR. JACOBS: So the serving of that lower load is what Tom is referring to. The performance of the capacity obligation of the generator is essentially what I'm talking about. So this is a sort of deeper question about is the generators that you have got committed, that you are paying in winter, they can't all run in the winter at the same hour at full output -- at their capacity obligation.

So those are both mutually true or feasible outcomes whether they're wise under single policy, you know, Joe was going to tell us.

MR. BOWRING: So two things don't surprise me here. One is that the loss of load expectations out here in the summer -- what a surprise right? It's only been true for the last 100 years then why is it shocking to us now, of course it's true.

And secondly, of course generators are not all going to run at full output in the winter because you don't need them to. I don't understand what the problem there is either but maybe I'm missing something.

So the thing about LOLE is it's a planning concept and it's -- if you look at prism it's a very, you know, narrowly defined model, it's been around forever. I read the 2003 documentation which appears to be the most current documentation.

I think it gives people a false sense of accuracy about its appropriate role in defining what a capacity market should look like. The capacity says that the insular capacity is greater than the tail of the distribution of load then there's no problem.

But the loss of load expectation is actually not based on operational reality and actual fact -- we've seen that. So under even RPM and even under IRP in the olden days, the market understood that there was a higher LOLE in the summer and actually purchased resources either defined or purchased the resource mix to match that.

So you had CT's which were effectively summer only resources except they also had availability whenever you needed them for peaks during the rest of the year and that frequently happened and it frequently happens in PJM.

So of course, loss of load expectations are higher in the summer -- the market has actually provided primarily summertime resources -- that is resources whose economics depend on lower capacity costs and running fewer hours and it being available for peak, but they're available year 'round for peak.

The polar vortex while it may or may not be appropriate to use the 2014 outage rates, it illustrated the frailties of relying on these models. So, you know, there's going to be some other thing that we didn't forecast as well and the idea that we can narrow down the exact loss of load expectation to the point we've been talking about I think is unrealistic.

But just to go back to some of the assumptions underlying the prism model which I think are inaccurate -- one, it assumes that DR is a perfect substitute for capacity performance resources. Another is it assumes that wind resources are a perfect substitute for thermal resources.

It assumes that solar is a perfect substitute for CP resources. It assumes, as we've heard, non-correlated outages and there has been some adjustment for that but it does not take account of the fact that it's very likely that DR outages are correlated, wind outages are correlated and solar outages are correlated.

So as far as I can tell, not taking account of that -- it's not taking account of DR fatigue. The fact that after multiple days of really high temperatures for example, or really low temperatures, DR tends to reduce, it doesn't take account of units at risk -- entry and exit, not fully modeled, it doesn't take account of common mode failures, it doesn't take account of what are winter gas issues, the higher level of reliance on gas.

I know the resilience issues that have been talked about in PJM's N minus 1 modeling of the gas distribution system and think about how it actually defines being scarce. Is it when generation is less than load? Generation minus load is zero -- is that the definition of scarce?

Does it include spinning reserve in the definition of load? Does it include primary reserve in the definition of load? Does it include 30 minute reserves in the definition of load? Does it include operator actions in all that? How does it deal with voltage reductions -- does it count that as being short?

How does it account for the new definitions of scarcity -- would it be ORDC curve, the new reserve targets, locational definitions of scarcity? So, just to -- a short list of some of the things that are not addressed in prism and then if we're thinking about -- about a fairly dramatic change to the capacity market you need to realize that it's not just a mechanical change that it has very significant longer term implications.

It would probably take a significant amount of time -- it would take a significant amount of time to redesign the market so that it really worked, summer/winter if that's where people really decided they wanted to go, thanks.

MR. MEAD: I guess my next question is if -- I think I heard some agreement that if you start with the current annual construct in a way that satisfied the 0.1 LOLE PJM-wide, would it be possible -- it sounds like it's possible that we could procure slightly more capacity in the summer months when LOLE is high and reduce the amount of capacity that we procured in the non-summer months by a greater amount and that by doing so we could make those adjustments so that we preserve the 0.1 LOLE PJM-wide.

And also in doing so if -- if summer only capacity is sufficiently less costly, we could make that change and lower total costs -- is there agreement on that principle or disagreement?

MR. COCCO: If I could just answer one question over here just to tie up a loose end and then I'll start to answer that question. Just on the transmission issue in winter, just my opinion having run power flow studies because of ambient temperature conditions you have more capability in the lines in the winter and therefore it's more likely the generation is delivered so I don't see this like an increase, kind of going on -- this discussion, I don't want to make -- to leave the Commission in thought, I think there's more risk in the winter period because of this, I don't agree with that.

Joe made a couple of comments that I agree with and before I answer your question I just -- the IRM is a planning study not reflective of operational conditions. And it doesn't reflect the fact that you have correlated aggregates. I completely agree with that but I do also believe that there is so much dominant calculated loss of load probability that's calculated -- concentrated in the summer that you can make these reasonable adjustments and still the majority of the loss of load expectation would still be in the summertime.

And because of that it creates opportunity for seasonable supply-side resources to then compete in this market because you have a summer dominated system so this ties in to your question. Yes, because of that trade-off that you described that you can allow summer seasonable resources to compete, only over the summer season, it could greatly reduce the need for annual capacity and you would then be as the administrator of this process, you would procure capacity in a way that could reduce costs to consumers because of this discrepancy in the loss of load expectation of cost a year.

MR. MEAD: Tom?

MR. RUTIGLIANO: Thanks again, Tom Rutigliano for

MA and the short version in answer to your question is an unambiguous yes. For the last couple years as part of the actual official option parameters, PJM has published studies, you know, saying that you could reduce winter capacity by 10 to 16,000 megawatts with a 1% increase in LOLE.

Now those numbers may change as we refine studies but there's no doubt it's a large number. And then the, I believe, non-controversial part of the more recent studies is that you can decrease summer LOLE by 1% by adding a few hundred megawatts.

So the exact ratio might be a question, but there's a many to one ratio between what gets you 1% LOLE in the winter versus the summer I think is not really controversial I'll say. And ultimately that's a pretty straight-forward result because there's declining returns to capacity.

When you're right at your reliability margin in a given week, a little bit of capacity really helps you a lot. On the other hand if you've driven risk down to near zero, it really can't get much better no matter how much more capacity you pile on you're not getting anything for it.

So yeah, ultimately yes. To some degree there are going to be trade-offs beyond just a flat capacity allocation that reduces total cost.

MR. MEAD: Mr. Falin?

MR. FALIN: Tom Falin from PJM. Yeah, the first half of your question I guess I agree with completely in terms of what our model results show that yes if you were to just go in and manually start spreading the LOLE across different seasons, the increase reserves in the summer would be a small fraction of the decrease you could see in the winter -- whether that ratio is 5 to 1 or 10 to 1 or whatever, we can nail down.

I don't think we have an official number yet but I guess in my mind I don't necessarily see how that will result in lower consumer costs. I mean true, you could procure perhaps a lot less in the winter but in my mind it's all about market signals.

You'll also have some resources now that will be recovering capacity revenue for only 6 months of the year instead of 12 months of the year so do you need to have a different BRR curve? Do you have to recalculate how you compute net cone? So I think there are just a lot of market implications that to me at least don't -- you know, definitely say oh no, the costs will be lower for consumers.

And even the RPM option that you're running is only three years out obviously. I mean there's still a concern about well what about 5 to 10 years out? So I'm not a market designer myself but you know, based on the signals three years from now, do you feel they will be sufficient to incent, you know, new resource build 5 to 10 years from now.

So I guess I'm not completely convinced that making these kinds of changes would necessarily reduce -- result in lower consumer costs in the long term.

MR. MEAD: I didn't see who went up first so -- following the line here.

MR. JACOBS: So it's my opinion that we were already running this experiment that we operate with less procured or I'm sorry, less deliverable capacity in the wintertime because of the point I made that we don't actually have the ability to run all of these generators at the same time.

So you know, in the final resolution of this question -- may my children see the day, we will perhaps get this cleared up about what's actually being understood as a loss of load expectation for wintertime. But right now I think we -- we don't have, we don't have a flat line of capacity across the winter. The charts that were used in the capacity performance little display -- there's a little cartoon about the base resources.

It actually went up a little bit in wintertime for the generator output but you know, if you ask the results of the transmission studies, are all the generators deliverable the answer is no, we've been running without them all.

MS. WIERZBICKI: I'd just like to ask a quick follow-up question. When we use the words transmission deliverability I think I'm hearing those words being used in two different ways on the panel.

So one is -- a particular generator, can it deliver its full output to the system? So is there enough capacity in the transmission lines to deliver the output of that generator without overloading the transmission?

The other sense I'm hearing more from Mr. Jacobs, is if we do an aggregate study of all the generators delivering their capacity at once, both -- is there enough transmission to accommodate that but also is there enough load to even test the condition?

And if the load isn't high enough to accommodate all of the generation, then you just have too much energy. That's not traditionally what I think of as a transmission deliverability problem. So I just wanted to clarify when we say transmission deliverability do we mean the limits of the transmission system or do we mainly have enough load to experimentally test that we have all this energy from the generators to have somewhere to go and can it get there?

MR. JACOBS: So I think the proper word is generator deliverability and because we've got this in the RPM framework that each generator has an obligation -- the question is how did they establish that obligation and how do they perform that obligation?

So I think it's correct that all of these concepts exist and are separately study-able. I think the point I've been trying to raise is that if you thought you procured the same amount of generation for all weeks, all months of the year, you have to understand that not all of those generators could perform if asked to perform, during lower load times because as you said, the load's not there.

My point is simply that in the response to the current question, Mr. -- I'm sorry, Mr. Mead asked, we are going through these winters without all the generators being deliverable.

MS. WIERZBICKI: And I guess my confusion is if the load is lower than the total amount of generation, why would PJM ask all the generators to deliver at once if there's not enough load to meet that much energy? I'm not sure I understand why that's the issue here.

MR. FALIN: Tom Falin from PJM. I kind of see it -- I see it from your perspective. We have a generator deliverability test for the summer that ensures that under peak summer conditions all the generators can inject up to their summer rating on the transmission grid.

I think as Mike has pointed out, if anything the thermal ratings of the transmission lines are greater in the winter than in the summer so it is kind of assumed that yes, if it's deliverable under summer conditions, it can also be delivered under winter conditions.

When I talk about winter generator deliverability, I'm actually referring to the ambient uprate -- if you want to call it that of some thermal units where they can actually exceed their summer output in the winter -- that test has not been done other than for wind.

MR. MONICK: Mr. Bowring, I think you had your card?

MR. BOWRING: So again, I was waiting for that part to end. So I mean the direct answer on the map that LOLE of course, the answer is yes, but the question is what does that mean? Does that mean we can really redesign the capacity market and kind of carve out summer only?

Well, we actually did that with the summer only DR product and it showed that we can suppress a price below a competitive level. I don't think that's a goal. So I mean the goals have a competitive outcome -- not to make the price too high or too low but to have a competitive outcome which is consistent with a sustainable market.

And again, to repeat what I said before, the point of the capacity market is not because you can use capacity to turn on a toaster because of course you can't. That isn't really a thing. Capacity markets exist in order to make the energy market work efficiently -- that's the reason they're there.

So if you're in aggregate, not forming a reasonable expectation of new entry when the system is tight, being able to recover all of its costs, then you're not going to get entry and the design won't work.

So it's a long way of saying that the point about getting from LOLE and the prism model to a market design is a very complicated -- it's a complicated exercise and it's more than simply saying you just cut the peak, let summer only respond to the summer only and everything will be fine -- because I don't think it is that simple.

And we need to distinguish between competition among substitutes and competition between one type of resource and another type of resource with different characteristics, and I would say inferior characteristics. So, it's, you know, it probably could be done, it can't be done in 6 months, it might take a few years to actually design a summer/winter market, but there's no guarantee whatsoever that the total costs would be lower.

And I had started off with a long list of assumptions that are not addressed in prism that might well result in a very significant change in the allocation of risk and the allocation of capacity cause across seasons, thanks.

MR. MEAD: Just to follow-up you say there's no guarantee that if you change the distribution of capacity to provide more capacity in the summertime and less capacity in the winter there's no guarantee that doing that would lower total costs.

In your view, do you think that it's pretty certain that the costs would not be lowered?

MR. BOWRING: Yeah I mean, so again taking an example from this morning. Imagine that all of your summer resources are DR. So DR doesn't provide energy -- in fact it's only an emergency resource. So suddenly gone from say substituting DR for peakers and imagining as CT's instead -- CT's would be available to provide energy as needed, but that is not true for DR.

And every time you call on DR it's a performance assessment. That means every time you call it it's an emergency, you've got scarcity pricing, you have a whole series of other events that occur. Those all result in higher prices. If you have an ORDC in the energy market or perform an assessment it means higher prices and it means -- so it means putting the system into an emergency simply because you're calling on one of the resources that you think is a substitute for the others even though it's summer only.

And you need to account for the fact that you still need a base -- a base of traditional resources to serve year 'round and the design has to assure that they have the opportunity to recover the costs as I said before -- if they don't it won't work.

So if, if for all the reasons I mentioned before the need for capacity is higher in the winter than prism is currently defining, then it might well be that the total costs of capacity are actually higher than what's being procured now.

But certainly the other cost, the energy market costs, scarcely related costs as a result of triggering performance assessment hours it would be significant -- it could be significant as well.

MR. MEAD: And Mr. Cocco?

MR. COCCO: Yes, so to the question does a model that would allow the pool to procure summer resources lower costs? And you've heard some answers -- maybe yes, maybe no. I'm going to say absolutely yes.

And I think there are two intuitive arguments to this. One is when you look at a pool that has 20,000 more megawatts of load than winter and it has potentially through changing supply-side resources, a lot of solar resources and other summer programs. The fact that you can match those up intuitively says you would be able to lower costs.

The more factual -- during the transition options in the recent years where PJM allowed you to procure what they call base capacity at that time was really just a summer only product. And in those two options it did lower the cost of capacity to the pool -- so I think those are two factual data points you could point to.

Now, I'm not proposing something equivalent to the base capacity product that existed in these transition options but more of a CP summer product that has all the obligations and requirements of an annual CP product -- just over a shorter time period.

Now, to the point that was raised on crisis suppression -- I do disagree with that. I think it will result in lower capacity park -- capacity costs, but that's a good thing. That's markets working efficiently. That you're allowing resources to compete, allowing PJM to optimize the selection of those resources and the fact that prices go down in a competitive marketplace isn't price suppression, its competition at work.

MR. RUTIGLIANO: Thank you, Tom Rutigliano for Advanced Energy Management Alliance. So the question you raise about what is the optimal risk or resource allocation? I think it's ultimately only addressable at option time, not purely by planning studies simply because you need to both know how much capacity you need and how much is offered.

But I think what planning studies can give us is a range of acceptable outcomes, you know, just to use round numbers -- planning studies might tell us that PJM can be served by 170,000 megawatts of annual capacity or 150,000 megawatts of annual plus 21,000 of summer or any point in between those.

The option can optimize and find the least cost solution within that parameter space. Now, I think where Joe says price suppression I might say cost efficiency and we can kind of debate the semantics on that.

But if the solution actually is at the least cost solution is say 150,000 of annual and 20,000 of summer, the market will send the correct price signal to get us to 150,000 megawatts of annual. And yes, that will be a lower price signal than if we needed 170,000 megawatts of annual.

But I think saying that once you've added this market efficiency, the price signal says something you need to know in a less efficient market design is told to retire is not price suppression, that's progress.

MR. BOWRING: So you may know that I'm not either in favor of high prices or low prices. Low prices are not necessarily bad, low prices are not necessarily good. They're good if they're competitive and the same thing with high prices.

So it's not what you call it, it's what it actually is. So not all annual capacity is created equal --

so the problem with the prism model is it assumes all annual capacity resources in fact, all capacity resources are created equal. But in fact we know that even with the de-ratings of wind and solar that wind for example is not there for any of the -- or it's there at a much reduced level well below even the C red level for the top 30 hours in the year.

Solar and wind are both not there for everyone in the top 100 hours of the year. So you can't simply assume it looks like a normal resource. There are outages that are unpredictable and they're highly correlated within the product type.

So it's not reasonable to assume that all of what you call annual resources are the same thing for purposes of thinking about loss of actual practical operational loss of load expectation.

MR. GOLDENBERG: Dr. Bowring, you mentioned that the experiment that PJM ran in the past with summer only produced lower than competitive prices, on what do you base that conclusion?

MR. BOWRING: So what I base it on we've done multiple bases induction reports to both document it and explain it but the short version of it is that if you have an inferior resource with limited requirements competing against a full obligations resource, of course, they will be able to provide that more cheaply and that will suppress the price compared to a competitive level.

A competitive level would be if you had everyone that was a substitute competing with one another. But if you have DR for example, it was not a full -- in that case limited summary DR was not a full substitute for annual resources. It's not a substitute, it's an inferior resource and to the extent that it clears the option it will suppress the price.

And we documented suppress the price to the tune of billions of dollars.

MR. COCCO: I would agree with Joe if you are providing -- Mike Cocco, I agree with Joe, if you are providing an inferior product that will suppress the price. But if you're providing an inferior product you're lowering the reliability objective below the 1 in 10.

What the people on the following panels are going to be posing something equivalent to the annual products. It's going to be a summer only CP product with all the same performance standards so it will -- you're not degrading the system, you're just meeting that reliability objective in a different way.

MR. BOWRING: Could I just very quickly ask you -- am I allowed to ask him a question?

UNIDENTIFIED SPEAKER: You can -- .

MR. BOWRING: So do you think 100 megawatts of DR which is an emergency only resource looks just like 100 megawatts of CP -- with references of actually meeting load in the summer?

MR. COCCO: You're having trouble transitioning from the prior panel focusing on DR?

MR. BOWRING: No, I'm not. Actually I'm just asking a simple question.

MR. COCCO: Or I think I'm proposing there's a whole bunch of supply side resources, some could be the only ones capable of generating the summer like solar, some could be load management DSM programs as you've described, some may be ones that are just more economically for a -- for you to just offer in the summertime.

So I think if you factor -- so is DR exactly equivalent to annual capacity -- no, but I think you need to account for that in the outage statistics that generate the capacity tags in the pool, so I think you adjust for that to make them equivalent.

MR. MEAD: If I could go back to an earlier part of this hour. Mr. Rutigliano, I got it I think, could you -- I believe you made a statement earlier about how treatment of resources might undermine capacity performance? Could you elaborate on that statement?

MR. RUTIGLIANO: Okay, absolutely. One of the things that's been working the background of the planning studies is that there's more need for capacity in the winter than the current crop of studies actually tells us.

The reasons given are, you know, correlated outages, perhaps a gas outage or something simply caused by weather generally fall under the idea of winter operational risks.

And so this idea that we need to pump up the capacity requirement in the winter -- however that then creates essentially two different measures for how much capacity generators contribute.

On the one hand we look at an individual unit and we say it's delivering according to its UCAP rating. But then when we do the reliability analysis you say well we're really down rating our entire generation fleet because of these correlated outages or so on, right?

And so that ends up shifting risk from suppliers onto load. We're buying a certain amount of capacity from generators saying we don't think -- we think there's a meaningful risk, it doesn't deliver what we've rated it at so we need to buy more.

Now on the capacity performance rulings, the Commission was unambiguous that even if it's through no fault of their own, any limitations on generator's ability to deliver capacity has to fall on the generator right? The

Commission addressed that when it was talking about, you know, out of management control events that are generators penalized for transmission outages and so on.

So if we go down the path of bumping up the capacity requirement because we don't fully trust the reliability analysis of generators in the winter, we've shifted that winter risk onto load and away from the generators.

MR. BOWRING: So I understand the point but as an objective fact prism is being used in order to evaluate what the loss of load expectation is not how people are responding in the market. And if it is a fact that when the wind goes down all the wind generators are reduced at the same time -- when the sun goes down, solar resources go down together and in the same area or gas resources on the same pipeline go down together -- that's a fact and that's something that the LOLE needs to account for.

It's not absolving generators of their requirement obligation to perform, that remains exactly the same. But if PJM's goal is to evaluate the actual likely outcome under a range of scenarios, they are obligated to account for that.

MR. RUTIGLIANO: And again I agree in principle with Joe. I guess in response if we're worried about -- fleet-wide correlated outages of the wind fleet or the solar fleet or the gas fleet in a paper for everyone's construct, the only correct way to do that is to apply a technology-wide de-rating of the technology at risk.

It is not to simply bump up capacity and have load pay for it right? The core principle to pay for performance is that performance relies on the supplier. You can't both say we're worried that gas might not run in the winter but then pay it at its rated capacity value.

So that's all I'm saying, I'm not saying contradictory reliability analysis, I'm saying you have to be consistent between how you plan generation and how you rate it in the market.

MR. BOWRING: I agree and so let's just say we purchased a bunch of capacity and it all underperformed and you expect it to continue to underperform. They would pay the penalties, they would bear the economic consequences that would all work as it was intended, but that also does not mean that PJM should not account for those actual facts in assessing loss of load expectation which of course they should.

So the two ideas are not inconsistent.

MR. COCCO: Yeah I mean we allow the market to drive the reliability of the system. We don't have a central planner out there saying someone should be putting in this capacity, this amount of capacity. We allow market signals to do it. So in Joe's example, if a generator was getting subtly beat on because it wasn't meeting the CP performance penalty and paying out more in penalties than it was receiving in capacity, we have to trust the market to allow -- to allow that market to tell that generator to get out.

We have to assume that happens. We have made a decision to trust the market signals here already.

MR. MONICK: One of the things we heard in the comments was in terms of shifting some of the risk to the winter, the people brought up the polar vortex as a possible negative to that. And then as a response some comments said well that was an operational issue as opposed to a capacity issue and I wonder if anybody had any response to that argument?

MR. FALIN: Okay, Tom Falin from PJM. That's exactly right. I think the polar vortex forced outages that we saw I guess back in January 2014 opened a lot of eyes and it's really what kind of drove home the point that you cannot assume that forced outages are independent of each other. So we made some changes to the model and then of course one year later or 13 months later there was another polar vortex in which generator performance had improved a whole lot.

I think instead of the 22% forced outage peak we saw in the first polar vortex, it had dropped to maybe 13% or so. So in all the analysis that we've been talking about here this morning, PJM believes that okay, the first polar vortex, very poor performance, should not happen again.

In a world with capacity performance and all the incentives to have the chance of that 22% system-wide forced outage rate happening again is extremely unlikely. So in all the analysis that we've been talking about here we actually took the second polar vortex performance data and assumed that it had occurred in the prior year also, okay?

So the second polar vortex performance filled in for the first one. So PJM acknowledges that because of the steps -- the operational steps that have been taken and then the implementation of CP, you know we don't believe generated performance will again be as poor as it was in the first polar vortex.

So that has been replaced in the analysis. But again, I think what was also driven home by that event is that -- that you know, a true loss of load risk can occur in the winter period if you get these unlikely circumstances happening at the same time -- extremely cold weather, extremely high loads, fuel delivery problems, common mode outages among generators -- so the likelihood of that happening is not very large, but it does have to be reflected in our model.

So it happened that particular year and so what we learned from that experience is that once you properly account for these additional seasonal risks in the winter, is that indeed, that full 30% ICAP reserves in the winter are required if you keep the summer requirement the same and you wish to maintain the one day in ten LOLE.

MR. MONICK: Mr. Cocco?

MR. COCCO: During the 2014 polar vortex the generator performance was extremely poor -- not question about that. I mean the peak -- the generators operating the region didn't have experience with cold weather, it didn't occur in quite some time leading up to that.

And the capacity performance rules were not yet in place. In the following winter with the CP rule changes and all the additional investments in generation such as back-up fuel, firm transportation and generators undertook other weatherization procedures.

And then overall the several instances of cold weather since 2014 polar vortex, generation performance was significantly better. So I would -- it's my opinion that I think the evidence has shown the 2014 polar vortex was not a reliability planning problem, people like that Tom, but was a combination of operating planning issues, gas electric coordination issues and the lack of generated performance incentives which have been corrected.

MR. MONICK: Mr. Bowring?

MR. BOWRING: So the idea that the response to that event could be that oh, it wasn't an LOLE issue -- it was operational. Well of course it was. But that's the point -- LOLE misses a lot of things and I'll say it again I set if off of the list of other assumptions that are not addressed in the prism model.

Those could all have equally significant impacts on the outcomes and it just illustrates the fact -- highlights the fact that you have to be very careful in relying on simple LOLE model results to support a very dramatic change in the structure of the capacity market.

So those assumptions matter and the whole problem is that we will have operational issues. There's always a reason why the last black swan event will never occur but you know, it's pretty hard to predict the next one, that's why they call them black swans although actually a black swan bit my daughter when she was five years old, so I've been to real black swan events, so I've seen them.

So the point is you can't actually predict them and you can be quite sure that there will be some explanation after the fact why the next one won't occur again also. Of course it didn't happen in 2015 because people have started their CT's for the first time in 2014 after five years, of course it didn't happen in 2015. But what will happen after five years of moderate winters -- could it happen again? Of course it could.

So the idea that it can't happen again is simply not true. The fact that it didn't happen in 2015 is obvious and irrelevant.

MR. MONICK: Mr. Jacobs?

MR. JACOBS: So I just wanted to add the experience from the polar vortex in 2014 included the performance of generators and demand response that weren't under capacity obligations to perform so we had the benefit of folks who were there even though the capacity market hadn't obligated them to be there.

And if you look further you'll find there are more resources like that than we realize.

MR. MEAD: Let me see if I can articulate this question. There seems to be some increasingly unique winter risks as you mentioned from the polar vortex experience. This is rolled into an annual need but if not today under what circumstance would it make sense to not roll into annual need and instead seek resources to meet seasonal needs and threats, Mr. Rutigliano?

MR. RUTIGLIANO: Excuse me, Tom Rutigliano, AEMA. Ultimately you're going to get more closely your resource procurement matches your need, the more cost efficient the market is going to be. So to the extent that you can say

PJM has distinct capacity seasons with different risks right? You've got winter risks, you've got summer risks. You know the fall, the shoulder months are relatively benign.

You know as Joe says we never know when the next black swan event is going to blindside us and we don't know if it will be in the winter or the summer. But I think you'll always get a more efficient outcome if you first refine the models to quantify as many risks as you can. I think failing to do so verges we're not doing our due diligence.

Bumping up that we need to for the unknown unknowns and then allocating as precisely as possible and procuring in its cost efficient way to meet those risks -- so yes, I agree that to the extent we have unique winter risks or it makes sense to say that you might, you know, incorporate those into our winter planning needs, but then that becomes winter seasonal risks which potentially could be addressed by winter capacity if it does emerge that there's a real need there.

Again we're verging into markets that probably ultimately and annual plus winter plus summer is the best fit for PJM's actual reliability needs but one way or another -- the closer the fit the better the market.

MR. MEAD: Joe?

MR. BOWRING: Again, I think -- I think it's tempting to believe we can narrowly define the -- and correctly define as ante the reliability needs by season. I just don't think we have that level of precision. I think the prism model kind of confuses as we economists are fond of doing precision for accuracy right?

I mean they're very precise and really, really wrong and I'm worried that that's what the prism model is giving us. So it clearly plays a role. It's been used successfully by PJM to maintain reliability for the last 90 years or so -- so that's all good.

But when we start to think we can fine tune to the point where we know that we don't need 17,000 megawatts of capacity in the winter, I think is probably pushing beyond the realistic limits of that.

We do need to think about there are a whole series of assumptions the model's make about what's happening in the summer, winter -- all of which need to be addressed. And if we can make the model work better that's great, if we can refine it to the point where we can actually change the capacity market design -- that's great.

But changing it is not simply a matter of saying, you know, we have some extra capacity in the summer, let's meet it through summer resources it's much, much more complicated than that.

What happens to the market needs -- other people have looked at what happens to most operative requirements, what happens if we perform the assessment hours, what happens to the definition of aqua caps, I mean we can go on and on. But the markets openly have to be sustainable and all of this has to fit with a sustainable economic model of how the markets work going forward.

MR. MONICK: Just one more comment.

MR. FALIN: Okay, Tom Falin from PJM. I was just going to add to Joe's comments. I appreciate the list of about six to eight things that we have to go back in our shop and try to improve in our prism model, but I think Joe's overall point is valid that you know, if we were to make a fundamental change to the capacity market in the way we allocate risk and the seasonal nature of perhaps procuring resources, I think it would require a deeper dive into are we computing all those LOLE numbers correctly?

Again, there's the issue of planned maintenance -- I had just mentioned the planned maintenance for generators in the winter. There's also the fall and spring. The fact that is our model optimizing that to the extent that it cannot match what we do in operations -- so I think that's just kind of the tip of the iceberg that if we were to really get more granular in our analysis here and then transfer that over to capacity markets, there are definitely other considerations as Joe share with us all, that our model would need to account for.

MR. MONICK: Thank you again to everyone for coming. Let's take a lunch break. Be back at 1:30 for the last panel, thank you.

(Whereupon a lunch recess was taken to reconvene at 1:30 p.m. this same day.)

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

MR. MONICK: Welcome back everyone. We had some good discussions this morning. I'd like to welcome the panelists for our last panel of the day on Seasonality and the PJM capacity procurement process.

We have with us today Steven Lieberman from American Municipal Power, welcome; Tom Ratigliano, from Advanced Energy Management Alliance, Stu Bresler from PJM, welcome; Sam Newell from the Brattle Group; Andrew Place from the Pennsylvania Public Utility Commission, welcome; Roy Shanker, on behalf of the PJM Power Provider's Group; James Wilson from Wilson Energy Economics and Rob Gramlich from Grid Strategies.

Welcome everyone. Thank you all for joining us this afternoon. This will be a fruitful panel. I'd like to remind everyone again who wasn't here this morning to turn up your tent cards if you're interested in speaking and remember to turn on your microphone and turn it off when you're finished.

The panel is scheduled to run until 4:15. We'll see how that goes. We're going to have a short break halfway through about 15 minutes. I guess in the interest of getting the discussion going why don't we start with our first question from the notice.

Are there feasible alternatives to PJM's current

LOLE practices that may better account for the seasonal needs of PJM's system. If so, what are they and what benefits would each provide? What transition costs would they entail?

Again, if you could introduce yourself before speaking that would be helpful. Should we start -- do you want to start at the end Mr. Lieberman?

MR. LIEBERMAN: Thank you, good afternoon. As others sitting here on the panels, thank you for convening this Technical Conference to discuss this issue.

As a representative from American Municipal Power, we were one of the listed complainants, so we certainly have given all of these questions a fair amount of thought and we hope careful deliberation and come up with ideas that we think are just and reasonable natures to them.

To the question about feasible alternatives, certainly we do think there is a feasible alternative to the current LOLE practice that basically contains all of that risk in the summer months and really its 6 weeks out of the entire year.

We wanted to -- we offered in our pre-Technical Conference comments as well as our original complaint some ways to modify the current practice. And one of the ways that we would propose to do that is through the inclusion of a performance period and a new product within that.

So it would be a summer capacity performance resource. We have an annual capacity performance resource today so our proposal would be that we have a single type of product -- capacity performance. There's no degradation of performance or anything like that where we're keeping to the CP requirements for performance and if you don't perform a penalty.

We're not advocating for a seasonal approach at this time but instead keeping the singular base residual option that PJM holds three years in advance, but we would have these two performance periods -- a summer and an annual.

As PJM was discussing on earlier panels, it provided some analysis at the request of stakeholders that showed how you could increase the -- I guess, peaking of summer capacity and reducing annual capacity and how that would shift through the LOLE from essentially 100% of the summer to something else.

And what we would not want to see is a tried and true requirement that 90 it would be split 90/10, 70/30 or something like that, but trying to maintain some sort of economic clearing mechanism that would produce an allocation of LOLE risk throughout the year in the most economical way possible.

It could be the way we have it today which is

100% or it could be something as -- in the analysis went out to as far as say 70/30. So there are ideas out there, we've seen ways that you could do that but I think we would have to start with a summer capacity performance resource product.

MR. RUTIGLIANO: Thank you, Tom Rutigliano from Advanced Energy Alliance -- Management Alliance. And before I start I was just reminded to say that my opinions expressed here reflect the AEMA but not necessarily each individual member.

We've largely agree with what Steve had said that ultimately the more closely capacity resources and capacity needs can be matched to the actual physical requirements, the more efficient the market would be.

As a starting point we look back and we see that for many years PJM had a well-functioning, essentially annual plus summer market. So if nothing else, there's something that's proven feasible.

Again, following Steve we think that if the option is allowed to optimize across a range of seasonal combinations you'll get more efficient outcomes than a fixed A priority 90/10, 70/30 split or so on, so that would be one possible improvement.

And then we believe that a potential winter -- I mean annual plus winter plus summer merits study as PJM both supply and need for capacity seem to vary across winter, shoulder and summer seasons.

Transition costs at least within PJM seem reasonable. We're generally talking about things that can be implemented within the option framework, perhaps some additional complexity in option clearing which is potentially non-trivial but I think at least at a high level it would be doable and fairly straight forward, essential to the planning process.

MR. BRESLER: Good afternoon everyone, I'm Stu Bresler from PJM. It's a pleasure to be with you as always this afternoon so thanks for having me. I think I would start out with first of all just sort of reminding everyone when we did have a summer only product in PJM we had that product and implemented that product with the full knowledge that there was an increase in loss of load expectation and we accepted, you know, with full knowledge of the fact that we had a 10% increase and that's how we set the cap for the summer only demand response product.

So with respect to feasibility of alternative LOLE calculations that maintain the same LOLE value, that's not what we used to have. So I'm not saying that is necessarily impossible in the future but I just want to make sure that that's clear.

When it comes to the loss of load expectation calculation and there were sort of shades of this during the first two panels -- at least the second panel this morning. The weekly distribution of risk that results from the current LOLE calculation is an output of the calculation.

It is as Tom I think, Falin really tried to differentiate -- allocation sometimes has the wrong connotation because it sort of intimates that we are pre-determining what the weekly risk distribution should be or at the very least what the seasonal risk distribution should be before we undertake the analysis and that simply is not the way it works.

We establish a reasonable rational set of assumptions that goes into the analysis and frankly I think some of those assumptions have been optimistic and we are -- as you heard this morning working on those such as the optimal scheduling of maintenance and the random distribution of forced outages and those types of things.

But again, the LOLE distribution that results as far as the 52 weeks of the year is an output of that analysis. So we think and the reason why we went to an annual only construct with capacity performance was that allowing aggregation within the annual only products really puts really the risk and the drive for innovation in the hands of the market participants so that there is a single homogeneous substitutable product which I think as you also heard this morning is extremely important for getting, also efficient competition to provide that single product.

But then under that the innovation of the market can be unleashed in order to figure out how they develop and how they determine or how they come up with annual products through aggregation of resources that may have capabilities in only one part of the year.

I would point out I think that even with capacity performance requirements around a category of resources that only has an obligation to perform in the summer is still a summer only product.

So we used to have performance requirements for the summer only product when we had one but the fact of the matter is once the resource is only required to perform and meet those expectations in one season it is a summer only product at that point.

So it's not like it's comparable with annual product simply because it has the same performance requirements when those requirements are concentrated in only one season. So it may be possible to come up with something that is sort of an economic kind of optimal division of how you might split the LOLE risk.

I would point out at the outset that I don't believe any other region of the United States utilizes different reliability requirements for different times of the year. And so if this is going to be addressed I think it probably needs to be addressed on a national level as opposed to something that is PJM specific.

But I do think that there would need to be some sort of objective kind of criteria for exactly how that risk would be distributed or apportioned throughout the year and perhaps again there might be some economic optimization that could be utilized to do it but I don't know what that looks like and again I don't know what that optimal -- sort of optimization program looks like.

But you know, so far I don't think there's really been anything kind of new as far as how we do the LOLE analysis today and how we come up with the single reliability requirement today. And as we all know that was judged and then sort of reaffirmed to be a just and reasonable approach through PJM's capacity performance market changes.

So I guess I would hold it out as a possibility but again I'm not sure exactly how it would work or how it would be accomplished and I think during one of your later questions we'll get to all the things that I think would need to be considered in coming up with that kind of a construct because I do think it would be a complete, sort of bottoms up redesign of how we do everything from loss of load expectation analysis to how the capacity market is structured.

So for now I'll leave it there and we'll get into the details in your later questions.

MR. MONICK: Thank you, Mr. Newell?

MR. NEWELL: Good afternoon and thank you for having me here as part of this panel. So I want to start by taking a step back for a second and remembering that a foundation of the PJM market's success is that it expresses the attributes that are needed and then let's all resources in the market compete to meet those needs at least cost.

And in this way the capacity market has attracted almost 70,000 megawatts of incremental supply of very diverse resources while dealing with retirements and it's viewed as a, you know, a major success.

Now, but one opportunity to make the market work even more efficiently and effectively meet the needs is to address seasons differently. And that means better expressing the different needs in different seasons and they do differ in quantity and in nature.

It means leveraging different seasonal resources capabilities to meet those needs and it means sending price signals to recognize the relative scarcity of capacity across the two seasons. And PJM's current construct does not do those three things I think very well.

And the thing is back to the loss of load expectation model. It's true that having most of the loss of load expectation or essentially all of it in the summer is just a consequence of having a summer peaking system and it's an observation.

But, having accepting zero risk in the winter is actually enforced by the way PJM prepares capacity by insisting that all resources have to be annual as if the winter peak were as high as summer which it is not.

Now there is a -- this provision for having matching up between summer resources and winter resources to try to accommodate different seasonal resources, but that's very limited and also a match should not always be required if the summer peak is higher, the winter peak is lower.

And when I say its limited there are many, many winter -- there's a lot of winter capability that could be offering that's not able to offer for matching right now and there is summer capability that was not able to find a match.

So the cleanest and most efficient way to deal with that would be a two season option. Now I understand from talking to a lot of people after submitting our comments that, you know, a lot of people view that as maybe a very large change from where we are right now.

So, you know, the question is could you approximate that with the past and the past construct with the summer only and I think with modifications you could. You'd need to hopefully accommodate more summer only resources, not just DR but also solar PV.

You want to express it as a demand curve rather than just a hard minimum. Incorporate matching like we actually have in today's market but actually expanded to accommodate the higher thermal ratings of -- higher ratings of thermal units and to enhance the price formation around how much the winter piece gets versus the summer piece.

So those are my sort of high level thoughts on how to approach this and I look forward to hearing from the rest of our panel.

MR. MONICK: Thank you, Vice Chairman Place?

MR. PLACE: Thank you very much it's a pleasure to be here. I appreciate the opportunity. I'll be brief so not to be repetitive of much of this panel so far. I'm in the camp I think firmly that we can and should utilize seasonal resources I think it brings an economic benefit to certainly to my jurisdiction.

I think there -- you can, even if we shift some additional capacity to summer it's more than made up for by reductions in capacity in the winter and picking out the diversity as Sam pointed out, we're stranding a lot of those attributes and for me that is a cost that is regrettable at least, so but we'll move on, thank you.

MR. MONICK: Thank you Dr. Shanker?

DR. SHANKER: Yes, thank you. A couple of introductory things, I want to say what Stu said and what Tom said one other way because I still think it's getting missed and the concentration of LOLE is an output, it's an output associated with an objective function and the objective function is to minimize annual resources ok?

And think about it makes sense. You take the most outages when the load is at peak right, you accept the most risk then and you concentrate your outage there and that minimizes the annual requirement.

One of the other properties is because one of the prism assumptions is the optimum ability to schedule outages. As I understand it at the zoning we just barely -- now this would change if we went to something seasonal, but at design we just barely have enough resources to cover the winter as it is now, which is keeping it at zero.

But it's at zero because the design criteria to minimize the annual resources said that's what it should be. So it's not this arbitrary shuffling. You can do that but you can't do it in the context of a specific objective function that we have now.

The second thing is the notion of in the --

MR. MONICK: The objective is to minimize the amount of resources procured, not necessarily the cost of procuring them?

DR. SHANKER: The quantity is fixed this way, the option would address the price.

MR. MEAD: Yes, but --

MR. PLACE: It's a homogeneous -- in the planning world it's a homogeneous product and there is no price. So I have little boxes with megawatts forced outage schedule maintenance and independent outages and that's it, so there's no prices. When prism says I need --

MR. MEAD: Sure.

MR. PLACE: "X" megawatts there are no prices.

MR. MEAD: Okay.

MR. PLACE: But it's trying to minimize those megawatts and then the consequence of minimizing those megawatts is the concentration of LOLE.

MR. MEAD: Right, but it doesn't say anything specifically about minimizing cost -- it's minimizing megawatts and --

MR. PLACE: In the reliability side yes. The planning side -- none of the planning has costs in it. You know, at least for reliability it's this -- what do I need? It's what Sam said, what do you start off with? You might say I need this in the summer and this in the winter.

This says I have so many megawatts I'm going to appoint when LOLE and what's the number of megawatts I need assuming an annual product and you minimize it. And when you minimize it you wind up getting a quantity that has the properties Tom described and moving that line down.

You're going to automatically concentrate your outage LOLE in a short period of time, because that's where we have the most to give to get -- if you want to think about it. The end results if you do that the trade-off would not show up in the annual amount.

Okay, one other and I will get to your question I promise is the historic comments about annual and summer is just so everyone understands again so it's not lost is that was not a movement of LOLE between summer and winter.

The historic program was a conscious degradation of the summer LOLE from .1 to .11 in order to accept an inferior product, okay? So that however their model looked and Tom is probably the better person to describe it -- what as people said will accept a degradation of overall reliability from 1 in 10 and we will in doing that, it was in the summer and they -- I think the way it was done it was either increasing the load or I think it was by increasing the load to see when you increase the capability -- the LOLE by .1 and in fact you can accept that much more of the product.

But that's a better question for Tom. But we're at a movement like -- and the discussion so far has been people crossing movement which is at a point, concept we can talk about that in some of the proposals, but it's different from what was done before.

The reasons -- I guess the general statement to your question could you do it -- yes. Is there an incredible amount of changes to the way PJM has to do business -- yes. I'm very wedded to the notion of a single homogeneous product. I get very nervous about evaluations, substitution, compensation, reference prices -- all the things we need and which are fairly transparent if not perfectly implemented plus all the lists that Joe Bowring gave before of exceptions that we take when we start to move away from a homogeneous single product.

Even if it's impossible though, but it's scary, the kinds of comments I've heard about selective cherry picking -- you know, just move this one over here and we're okay and we create all this room is very disturbing. I don't know how things will -- prices will set how compensation.

We're built around the missing money concept. I mean that's the building block as Joe said. It's not a separate market, it's to facilitate the energy market, the capacity market is to facilitate the energy market to make it work. The way it makes it work is by yielding compensations that are pointed towards that missing money.

The notion of supporting new entry or retaining existing generation -- that whole paradigm and what it means and what it means in the presence of multiple different products has to shift if you want to do this and it's a daunting problem. I'll never say, you know, I've said in comments I can probably model anything. You know, give me some time and I'll get you something.

I'm not going to be sure what the properties are and here's one where I think you're at the edge of playing with some very dangerous properties. If you want to do it, don't think we can put a little twist on the end of what we have now -- you're probably looking at a multi-year project with a lot of research.

The tools we have now -- I think you heard are not appropriate. We have to invent new tools or modify other tools that may be more appropriate, those are some of the things we could talk about on that.

And the winter deliverability studies would have to be done -- from Tom's, I need to talk to Tom there's a chance we do have the CTEL concepts in the winter but I don't know that they've been perfected, they certainly haven't been used. We don't have a need for them and in reviewing them in the past for other applications I found problems with them -- so those are just the tip of the iceberg.

So yeah, you can move but sort of simple minded I'll take 5 points of -- or 5% or 10% of the overall LOLE and shift it to the winter and we're done and we're running the option like before is not acceptable.

MR. MONICK: Thank you, Mr. Wilson?

MR. WILSON: Yes, thanks for having me. James Wilson and on these issues I've been consulting to consumer advocates to environmental organizations, public power, demand response providers over time and other parties too, but today my comments will be my own views.

So this morning I thought it was fairly clearly established that for a small increase in the summer reliability requirement you could establish a winter reliability requirement that was many thousands of megawatts lower and together meeting that summer reliability requirement and that winter reliability requirement would satisfy our one day in ten years LOLE .1 resource adequacy criteria.

And I thought it was fairly clearly established this morning that that's the case. And in fact PJM has updated its tools based on the polar vortex experience as Tom found and described to be able to calculate both of those reliability requirements and that trade-off. So I just start there.

And my first observation is if you move away from equal reliability requirements summer/winter which is what we have now with the 100% annual requirement. As you move just slightly away from that, you're making the system more efficient because you're recognizing the seasonality of requirements, you're recognizing that we've got stranded seasonal resources right now and you're accommodating those resources.

So moving away from that, even if it's a very modest amount such as 90/10 would do, already lowers costs, is more efficient, is less discriminatory, accommodates seasonal resources and establishes a price signal for the seasonal resources -- just any way you do that.

And there are a number of approaches. I would outline kind of three generic approaches. The first one is what Steve and Tom talked about which is, we -- PJM already had rules that could clear some summer resource within the option. It was doing that until capacity performance was implemented.

So we can start with those rules. We can make sure that summer product is not an inferior product. We can make sure that the constraints against which it's acquired are constraints we can live with. We can raise the summer requirement to make sure that we're not relaxing LOLE but we're still meeting 0.1.

So that's sort of one approach and then another approach that Sam mentioned is to go to a full seasonal construct where you set summer reliability requirement and a sloped VRR curve and a winter one and you hold the option where you're entertaining annual offers of course -- the vast majority of offers will always be the annual and also summer period capacity performance resources and winter period capacity performance and you're clearing them both together such that all resources -- all annual resources will clear as long as the combination of the summer and the winter price is greater than their offer price.

And that can be done either by setting those two VRR curves or as also been suggested some sort of optimization. I'd stay a little bit away from that because there's so many things going on in that option I'm a little concerned that optimization may be complicated.

And then I've offered yet another way to go that I don't know if we'll go that way, but I offer it mainly because it's so simple and it requires so little change to what we have now. The tariff already defines summer period resources and winter period capacity performance resources.

It already has the ability to accept offers from summer resources and winter resources independently, but it requires matching them up one for one in order to clear, okay?

So in my proposal which is an attachment to my comments which I call winter aggregation tickets -- PJM, first of all we would decide what we wanted to do in terms of that LOLE allocation. Do we want to raise the summer requirement by 500 megawatts to be able to drop the winter requirement by 13,000 or we have to choose that and we've got all the information to choose that.

Then once we do that, that gap between the summer and the winter -- PJM would create winter aggregation tickets on the basis of that and we could do it very conservatively in the first year and use a smaller number and it could option those to the market -- either as a fixed quantity or much better of course would be an upward sloping supply curve where the prices reflect marginal reliability value and the exact same concept right now that is behind our VRR curve shape.

And summer period resources would purchase those winter aggregation tickets and then be able to use them as a partner -- as an aggregation partner in the option. They'd be able to offer into the option with that ticket as the other side and all of the option logic could happen just the way it does now. Nothing would have to change.

And because that summer period resource would have to acquire through the option not only its own cost, but the cost of that ticket. It would be incentive to offer like an annual resource -- it would compete appropriately with annual resources so it would end up with the option operating exactly as it is today except there would be these new aggregates that are aggregated with the winter tickets which are, of course, not capacity just a ticket.

The option of the tickets which might be held a couple weeks before the base residual option, would establish a price for winter capacity so we'd have an explicit price for the winter capacity. So we'd have the annual price that of course, the vast majority of resources rely on and we'd have a winter price.

The summer price is the difference between annual and winter that would guide over time the development of future seasonal resources whether it's demand response which is seasonal, whether it's wind that tends to be seasonal, whether it's solar tends to be seasonal -- that price would sort of guide us over time.

So it's a very simple approach, it doesn't require any changes to the option. You just pick which of those resource adequacy analyses you like, auction off the tickets and then the auction goes. So I provide that mainly to show how simple it could be to move away from the 100% annual we have now, achieve a lot of that extra efficiency.

And in terms of benefits it recognizes the seasonality of the requirements. It lowers costs by being more efficient by accommodating seasonal resources, sets an explicit price signal which is extremely valuable as we go forward and more and more solar, wind and demand response are the resources that are coming, less discriminatory, so thank you.

MR. MONICK: Thank you, Mr. Gramlich?

MR. GRAMLICH: I knew I was doomed if I had to go after Jim. Rob Gramlich, Grid Strategies. For this I have been working directly with the American Wind Energy Association and Mid-Atlantic Renewable Energy Coalition.

We put in some relatively narrow comments compared to the rest of the folks here focused on just a couple general things. I guess I'd summarize that sort of the Commission should focus on real reliability needs and not pre-judge whether the reliability risk is in one season or another -- let's focus as with everything, focus on the real reliability need wherever and whenever it is.

And then seek to remove barriers to entry and we have a number of comments maybe for later about the areas to entry but we think that wind energy is providing something of significant value since there have been a lot of concerns about wintertime, not just summer, but more recently wintertime as well with winter being the highlighted time in the PJM fuel study that was cited in the Commission's resilience NOPR that is the main focus of the Commission now and the same thing is going on in New England so the two regions where real issues are talking more about the winter.

That was on page 33 of PJM's study if you want to look at that and of course wind is much higher capacity value in the winter and there are barriers to entry. I was persuaded by a lot of the demand response barriers that were alleged and there are I think some solar and some wind barriers so the new technologies coming into these markets that were largely designed 20 years ago and evolved over the years still have some barriers for the new technologies coming in.

For wind it's specifically mostly related to the asymmetric penalties and then I think for all of these seasonal resources the annual design of the market is a barrier to entry and the matching requirement is a barrier to entry so if the Commission could focus broadly on barriers to entry for all of these resources I think that would help.

I mean in theory just on the structure it does seem like with the new technologies that are in the market now, the winter and summer products are different products. I mean technically if you sort of went through a, you know, kind of a DOJ FTC hypothetic monopolist test, you know, which is sort of a Commission practice for determining which is a separate product or a distinct product, you would find they are different products.

So -- and you have a whole set of different suppliers in one than the other so technically in theory, I don't think anyone -- I didn't hear Dr. Bowring or others disagree with that notion. I think others have said well there's a major implementation challenge so that's I think where your later questions -- we can get into that.

My own view is if you're going to do a wholesale change in any of the Northeastern capacity markets you should think about well maybe we should really got the whole distance towards real markets and look at how ERCOT does it but that's a personal view.

MR. MONICK: I'd like to welcome our distinguished colleagues, Commissioner LaFleur, Commissioner Glick, if you guys have any comments that you would like to make right now -- no?

COMMISSIONER LAFLEUR: I feel like I epitomize better late than never but I wanted see some of the Tech Conference -- I believe I am now, so thank you for being here.

MR. MONICK: Did you have a comment you'd like to make?

MR. RUTIGLIANO: Please, thank you, Tom Rutigliano, AEMA and welcome Commissioners. I'd just like to respond briefly to the comments about the 11% loss of wood expectation in the annual plus summer construct made by

Stu and Dr. Shanker.

That -- those, that reliability level had been determined by taking our tried and true 10% LOLE studies and then simply relaxing the amount of winter capacity until there was an additional 1% loss of load in the winter -- that's what resulted in the 11% LOLE.

But I want to emphasize that decision was made essentially for convenience and in no way represents any sort of flaws of summer only capacity. And looking sort of in detail at the procedures of how PJM does its reliability studies it would literally be changing a single number to instead start with a 9% LOLE or 8% and then relax to 1 or 2% winter.

So again respectfully, I think the difficulty in getting to a 1 in 10 LOLE in a mixed product market are not that great and existing planning methodologies are well suited to handle them.

MR. MONICK: Mr. Lieberman?

MR. LIEBERMAN: Thank you. Steve Lieberman with AMP. A couple of things that I -- you know sitting and going first and therefore having to wait there was a number of things that I wish I had said so I'm going to add them now.

To clarify, the summer CP resource that I had described that's part of our proposal -- I need to make sure it's clear that this is different than what was in the PJM construct before which was a summer only DR product and there was an extended summer DR product.

The summer CP resource that we have described in our pre-Tech Conference comments would be open to all resources so thermal as well as DR and you know, the other environmental you know, wind, solar, et cetera, so it would be expansive.

The 1 in 10 that we talk about and degrading that as we had previously allowed -- I just want to emphasize this point, I think others had made it -- it is a planning concept, it's a criteria, it's not a requirement. We're not proposing that we relax that indefinitely to 1 in 11 or 1 in 9 or whatever it is.

You know, we are proposing to keep it at 1 in 10 it's how you -- when you add up all those numbers for each week how you get to .1 that we are suggesting and we could take advantage of the seasonality that exists today.

But the existing aggregation rules that Stu mentioned -- they are there, but they're not efficient. They ignore real opportunities for aggregation that are not allowed as others have mentioned. Thermal generators -- they perform, meaning they can produce more megawatts in the winter than in the summer but we're not allowed to pair a summer aggregation resource with those megawatts. So we're already looking at a system that has winter capability but we're not taking advantage of it or rewarding them for those megawatts.

Roy had a lot of fears so I'd like to try to allay some of them. One is this approach we think is actually rather simple. We did clear three products at one time in PJM's construct -- summer only DR, extended DR and an annual then we went to a base and an annual and a CP.

So we've been able to see the basis of the option clear with multiple products so we're not proposing something that would be so brand new that we would have to redesign the wheel. There are many benefits though on top of those that have -- others -- that others had said.

First is of course, accommodating seasonal resources, states and others have made a big push for that and we should enjoy the benefits of that through the capacity market. We should take advantage of PJM's changing resource mix. If we just keep looking at how it was done in the past and say well that's how we have to do it in the future it really is short-sided.

And finally, and then I'll turn the mic over to others is I did suggest that we would start with a summer and annual CP product but as Tom and Sam discussed and Jim as well, I think that, you know, we could take that baby step and incorporate a summer CP product but we should consider -- strongly consider evolving to a third product -- a winter CP, but you know, as we like to do take one step first would be to go from an annual CP to a summer and then add the CP, thank you.

MR. MONICK: Mr. Bresler?

MR. BRESLER: Thank you and first let me agree with Tom as to how we came up with the cap on summer only resources was in the past as far as reducing the kind of the assumed capability in the winter until we actually got to a .11 LOLE, but I think we're all in agreement that that was a conscious relaxation of the LOLE criteria.

So all I was saying when I said before that that's what we did, that's what I meant that's what we did. So it wasn't out of a matter of convenience, it was a conscious decision that we were going to allow summer only resources without bumping up the LOLE in the summer I guess in order to maintain an overall 1 in 10.

So if we went down the road of allowing seasonal resources again in the future and we wanted to do so without increasing LOLE then again, you would need to start kind of somehow in the middle of the process and say okay, well what distribution of risk do you want and start out with that first and then kind of back into what your reliability requirements are.

So we did not by virtue of the stakeholder discussion that has happened so far, revise our LOLE methodology. We ran sensitivity analyses that the stakeholders have requested us to execute because they were interested in kind of what these differences were. But that should not be read as a revision to our LOLE methodology. The methodology is the same.

We are -- as we had said this morning again, tweaking some of the input assumptions because of actual experience we gained during winter of 2014, winter of 2015 but the methodology is still the methodology.

So just to address some of the other comments that were made as well -- for example, allowing once again a seasonal participation if you are, a summer only resource participation being more efficient because it would lower costs and it was characterized I think as being less discriminatory.

I think you heard Dr. Bowring this morning articulate very well and it's a good opportunity to reinforce the fact that I agree with my Market Monitor on a lot of things. It seems like it only comes out when we disagree but we agree on much more than we disagree about.

And on this one we certainly do. Certainly, I would see the fact that prices go down, that costs, if you will, go down as a result of the allowance of what is I think been termed an inferior product, a product that only has to respond on a certain part of the year as suppressive of what the competitive clearing price is that you would get and that we are getting out of having a homogeneous product that all resources can compete to provide.

That sort of gets into the discriminatory part where it's less discriminatory to allow seasonal -- I would say that the annual resources on the system would say that that is discriminatory because they can't realistically compete to be a seasonal resource because they can't do so on the basis of economics.

So I think you can certainly look at that from the other way as well. But I think no matter what sort of alternative you look at and some of these were explicit in the comments that were read, some were not.

Some of them for example, say that in order to do this we should eliminate the ability to do maintenance in the winter -- so eliminate planned maintenance outages in the winter periods. As you know I lead the operations area, PJM as well. I am not comfortable with eliminating the ability to do maintenance in the winter because I think it's impractical to get it all done in the shoulder periods.

If you look at it and assume you can always do it optimally, maybe you think you can. I think in operations we need the ability to have resources allowed to be able to do maintenance in the winter as well.

I do think that some of these options, except for the one that I think is probably the least defined, does require some fixed allocation again, of risk up front which I think starts the process in the middle as far as LOLE determination is concerned.

If there is a way to do it more dynamically on the basis of economics I don't know what that looks like. That sounds to me like some sort of combination of the LOLE optimization algorithms and the auction algorithms themselves which would wind up somehow with the economic distribution out of the combination of the two of those.

But again, we'll get into them in one of your later questions -- everything that would need to be done to come up with that kind of a construct as well. So I think there's a lot of things I think that we need to make sure that we characterize appropriately as we go through this discussion, thanks.

MR. MEAD: Can I just reference those comments for a moment. I guess I have two questions. If we were to have a fully two season market as Dr. Newell proposed, does that remove the inferiorness of summer only resources?

And I guess my second point if it doesn't is there not still some value that solar and other summer only resources provide and at some low enough price? Does that not make those resources a better choice than your current annual?

MR. BRESLER: Yeah I think -- I think that's possible. So I think if you do a full-fledged kind of two season optimal, you have both seasons and you optimally commit for the aggregate requirement I guess in each season. I think it could, but we're going to go through again everything that it would need to take to do that right in a later question.

And I'm sorry I'm going to quibble with my good friend Sam's -- some of his analyses later on as well as far as again the quantification of that benefit and sort of what went into the assumptions of the calculations that Brattle did so far and then what I think would be necessary to really do a long-term look as to whether or not over the long-term this would result in actual lower cost to consumers, but I think that's like the subject of some upcoming -- some later questions so I'll hold that for now.

MR. MONICK: Vice Chairman Place?

MR. PLACE: Thank you. Yeah to build on what David pointed out and to answer Stu -- I find it difficult to digest thinking about this as inferior or price suppression to me is economic efficiency, particularly if you have two discrete markets.

And it's not necessary that we would get there overnight, you can return to the gradualism, you can return to the base capacity and annual CP products transition period and stick your toe in the water and also build upon a lot of that work that's already existing that should not -- I do not agree that this is somehow catastrophic or cataclysmic to go down this route.

To me it's an evolution from the markets we have today and we have the tools in place to ensure these are not inferior products but yet capturing the economic attributes that they exist -- whether it's winter or summer resources.

MR. MONICK: Dr. Shanker?

DR. SHANKER: Excuse me, tough allergy season. A couple things -- first I need to respond to Steve's comment about don't worry, we've done it before. And the simply answer is worry -- we did it before and we didn't do it right.

Three years went by and the constraints with respect to some of the -- call them summer if you don't want inferior, products were reversed. We actually had the dominant products not seeing a demand curve but seeing a vertical demand curve -- just the opposite observation of what Sam has in his paper.

I actually complained about it and a while later PJM reversed those constraints but the point was it solves. And like I said we can put together equations that will solve, it doesn't mean that the answers mean something and that they're consistent with what we're trying to do or with the underlying assumptions.

And you have to have enormous, enormous caution when you start to put together systems like this. We've had one unforeseen result after another as you can look at the parade of filings from all the RTO's that come before you and this is a fundamental change.

It is not something we have had before. It is not trivial if you don't think that it was an inferior product, understand that the way the models were set up -- not like what we're doing or potentially doing here, but the way it was set up a product that was potentially providing only 60 hours of service year at most was getting paid approximately the same as a base load unit.

The shifts that the Market Monitor talked about in the sensitivity studies show features like that -- 10 billion dollars a year in the shift between supply and demand -- non-trivial results and completely hidden because we've done it before. We had a model that solved it. People don't see it until after the fact.

We had built in discriminatory practices where portions of the load demand were removed. It still solved, but essentially you cleared 97 % of the results against all the resources of the load -- against all the resources.

It meant that if you never had growth at excess of 2   % you never saw marginal products and people wonder why you weren't seeing the cost in new entry ever coming and the clearing prices lower. Some people may have said that clearing prices were too high, but it's solved.

There wasn't a problem, we can solve that. Just have them take 2 % off and run the equations. Everybody says this is simple and you can solve it because we've solved it before and I'm telling you that it's that kind of uberous that has meant that we be here every single year, several times a year fixing the last mistake and you're setting yourselves up for the exact same phenomenon again.

All I have to do is move some of the LOLE -- you have to figure out -- let's assume one of the examples in the Brattle paper was put all of the net cone in the summer. First off you have to decide it's the net cone of what -- but let's assume it's the current net cone except that's a potential distribution. What do you pay somebody for the winter?

What you don't think they have annual products? Do we only have people that bid in the summer because there's no economic reason, there's no economic reason for an annual product in the winter if they can see a collection of all of its resources over the summer, so what do you do?

So you need a whole bunch of new mitigation rules. We need a whole new way to think about how to compensate to make people whole which the net cone concept that we have now that logically works, has worked, and we have to examine whether it's the right concept going forward right?

I'm not -- I'm not a doomsayer for this. I'm willing to say that you can attempt to do this and I think it might work, but when somebody says all you have to do is -- we have all the tools, you don't have to change that, you should run away screaming and say no.

It's just absolutely a huge mistake. There's no burden of proof has been met here, anything close to what it takes to do this properly.

MR. MONICK: Thank you Mr. Wilson?

MR. WILSON: Yes, James Wilson. I just mainly want to respond to these questions about inferior products that we've heard over and over again and -- because we're muddling two things here I believe.

First of all as I mentioned, the tariff already defines summer period capacity performance resource, winter period capacity performance resource. So if people want to take issue with those definitions, that's really about capacity performance outside of the scope, I think today.

We're really here about we've got the summer resources and the winter resources, how can we better accommodate them? So I really think that's the issue here.

Joe Bowring as we know, doesn't like demand response so maybe he thinks it shouldn't qualify as summer period capacity performance resource -- okay, take that up somewhere else.

So, once those definitions are in place -- these are not inferior products, they have the blessing in the tariff and so it's a question of a summer period resource and a winter period resource. Are these inferior products compared to one annual? And I'd say that ultimately it's for the Commission to decide. Is 6 plus 6 -- 12 or not? And so, that's all I wanted to say on that thanks.

MR. BRESLER: Sorry I need to respond to that if that's okay.

MR. MONICK: Go ahead.

MR. BRESLER: So I agree we need to watch our terminology and inferior I agree has as bad connotation and I wish we wouldn't have started using that term earlier and certainly today if not before because I do obviously agree with Jim that we do have seasonal if you will -- half year products defined in the tariff.

The concern comes in when you allow a seasonal resource to take the place of an annual resource without again -- to Roy's point changing everything else around that needs to change in order to make sure that that is done correctly. That is what we mean when we talk about the impacts of -- of a seasonal product in and of itself in the auction.

To the extent again that we can aggregate them to come up with an annual resource and therefore one is not in and of itself taking the place of an annual, we think we're fine. Otherwise, I think you get into all the price suppressive concerns that we talked about earlier today, so that's what that meant.

MR. MONICK: Let me get to Mr. Newell?

MR. NEWELL: Well I don't know if Stu just put the inferior idea that maybe I can still say a couple of things on that. One is that very fundamental idea about capacity and I want to make -- I want to respond to that Joe brought up before, this idea that summer products are inferior because they respond only in emergencies.

We're talking about capacity. Capacity is about keeping the lights on and to take Joe's point would be to say that combustion turbines don't have as much value as a combined cycle -- that's true, that's recognized in the energy market. This is about capacity.

Anything that can help keep the lights on has the same capacity value. So that's one point about inferior products. Now it is important to make sure to qualify resources properly and rate them, make sure they can really do what they say they can do. That they can -- and then to have strong performance incentives through CP and through energy price formation -- that's all important.

But so the other aspect of inferior that we talked about was, you know, serving one season's needs versus another. The summer peaks are 20,000 megawatts higher than the winter peaks so there is, you know, there is room for some summer only capacity without having to have a match.

And this idea of price suppression, you know it's very small in the sense that summer only resources have almost as much reliability value as annual because most of the reliability needs are focused on the summer.

And you only need so many annual resources in order to meet peaks across the year. And, you know, the price will still be set by the highest offer of the, you know, of the annual resource. I mean there's no annual resource that is getting paid less than it offered. I mean, you know, you get as many as you need and you set the price at or above all of their offers.

So I think this idea of inferior product and price suppression has been a bit overplayed. I also just want to respond to Roy's very wise comment -- his caution about saying this is easy. I think that is -- I agree. These markets tend to get very complicated and in unanticipated ways. I would also encourage to build on the innovation that PJM has already done and actually I want to second what Stu said before.

This isn't just PJM. This is all the RTOs and in fact PJM has innovated more than the others in experimenting with ways of dealing with seasonal needs and capabilities. So, but there is actually a lot to build on from the prior summer only products, from the current matching and you know, there are ways to recognize the difference in seasonal needs and the different seasonal capabilities of resources much better than I think they are now.

MR. MONICK: Mr. Lieberman?

MR. LIEBERMAN: Thank you, Steve Lieberman with American Municipal Power. So earlier today there was an exchange in the first panel -- Dr. Bowring said to one of the panelists to their point he said, precisely.

So to Roy I would say to your comment about we didn't do it right before I'd say precisely and that's why we're talking now. Precisely because the earlier summer only products we had were demand response only.

And what we are proposing here is a summer CP resource. It would have the same performance requirements as the annual CP product during those same summer months. So we didn't do it right before because we had a different product -- it wasn't open to everything.

We are proposing to have a product type that is open to all resources with the same penalties and performance requirements. And it would -- just as Sam said, it would recognize the seasonality benefits that exist.

MR. MONICK: Mr. Wilson, go ahead.

MR. WILSON: James Wilson, on the price suppression question again -- and I think price suppression is synonymous with inappropriate price suppression. I think whenever that word suppression is used, don't we mean something inappropriate rather than just a change that lowers price?

If changes are made to the construct so the currently stranded summer period resources can compete, it will likely have a little bit of a lowering effect on the summer and annual price. It will have that affect. It will be more efficient and lower cost, but it will lower the price a little bit, but that's not price suppression, that's just removing discriminatory barriers to participation.

So I think when people use suppression they're using it in a pejorative sense and in this case when we improve efficiency and that lowers price I hope we're not calling that suppression, thanks.

MR. MONICK: Go ahead.

DR. SHANKER: Okay just so that I'm clear. When Steve and Jim are saying annual products then we're agreed they're not talking about the same thing? They're talking about a current definition? You're talking about a proposed definition it would be 24/7 call all the time, is that correct?

MR. LIEBERMAN: So today we have an annual CP product and I'm saying we would rename that annual -- differentiate it from summer CP.

DR. SHANKER: But it would be 24/7 call all hours?

MR. LEIBERMAN: Yeah.

DR. SHANKER: And you're not doing that -- you're keeping it at the summer definition now? So this is really important it's a fundamental difference as to we have two different proposals on the table of what's the seasonal product and one has significantly different implications for performance, excuse -- someone whoever discussed no excuses before with respect to the CP design.

The current definition of summer under a CP would be -- would not meet that definition and what I'm hearing Steve say is that any DR under his proposal would be subject to like a 24/7 call also, okay?

So when we go from this side of the room to that side of the room I urge you to pay attention to the comments because the qualifications and what you need to do to change that are very different.

And the implications for how you do all the things we're going to talk about later are very different in terms of what the demand curves look like with the compensation looks like, what the objectives are.

MR. WILSON: James Wilson. So Roy, you're again trying to muddle the two questions that I hope we keep separate which is what is the capacity performance product? What is the summer performance of it, what is the winter performance of it -- that's one issue which I don't really think is within our scope.

And then the other is given that we have summer season products and we have winter season products, how do we accommodate an efficient mix of them given that our requirements are very seasonal? I think that's what we're talking about here.

So when I didn't get down into the details about how capacity performance definition perhaps ought to be changed, I thought it was out of scope, thanks.

DR. SHANKER: If I may respond to that. I just totally disagree with that. You read the Commission's order on CP that explicitly said it was talking about an annual CP product so that's where we're starting from, okay?

Steve is describing a seasonal CP product that but for time of year and I just want to make sure I don't misquote you, but for the period of year performs indistinguishly it's a box with megawatts, forced outage rate and maybe some requirements on outages which we will have to talk about later.

And Jim is not -- and so it is a difference because underlying all -- when you say seasonal if I tell you seasonal and it's a 60 hour -- I always get it wrong, is it 6 x 10 or 10 x 6, whichever it was the original summer -- that was tariff defined product.

I mean if that's what somebody was talking about it has very, very different implications and even though what we have now versus the product that Steve is talking about so it is material.

MR. MONICK: A little bit more time before the break, why don't we dig into this summer CP idea. If people have any thoughts on what the implementation challenges to doing -- operating something like that would be, maybe we could start with Mr. Bresler if you have any thoughts on that?

MR. BRESLER: Well I think the first challenge which we've already talked about ad nauseum is how do you come up with the cap on it? How do you come up with the division of a risk -- what you put in the winter, what do you put in the summer? How do you come up with what the annual requirement is?

So I guess that's challenge number one. I have a bit of a concern depending on sort of what proposal we're talking about. I think it could happen with this one as well. I understand what Steve and his folks are proposing is a summer CP product open to any resource type, but I'm also hearing that there is significant concern about sort of stranded summer demand response which you would think would have to take up much of what you allow to be summer only -- again, depending on how you define the performance requirements.

I think -- I think that still leaves you with a separate product, one that is not substitutable, with all the issues that we talked about before and I worry a little bit about what that means for the stability of the market if you will from you know, the departure from what we've recently achieved which is all annual resources.

In other words, if you begin to commit a significant amount of summer only and then I think Dr. Bowring paused at it that if you get a significant enough quantity you're going to be dispatching it in the energy market more often because you'll need to.

If that's not the expectation of those resources then they may not stick around when that starts to happen in which case you'd need more annual resources again but now you've already sort of driven them out. So I don't know what that means as far as the long-term cost of the market.

So that kind of brings me all the way back to how do we actually determine whether or not what we're talking about here actually does reduce costs in the long term. So depending on what other proposals we dig into later today, there's probably other implementation concerns as well but those are a couple that I thought of with respect to just saying we can have a summer CP again.

MR. MONICK: Go ahead.

MR. RUTIGLIANO: Thank you, Tom Rutigliano for AEMA. First off I'll start by saying what the AEMA's proposal generally speaks to keeping annual and then adding one or two seasonal products.

We agree with comments made by Dr. Shanker, Stu and Dr. Bowring on the order that annual is foundational RPM eliminating entirely would cause a host of problems. So within an annual plus construct, as Dr. Shanker said, you have some difficulty of pinning down the product definitions but we've come up with a capacity performance definition that includes energy efficiency and demand response and doesn't require solar to work at night and so on, so those seem to all be surmountable problems in terms of coming up with seasonal product definitions that are fair compared to the annual product definition.

So the two implementation challenges we have left would be the planning and the off-chute clearing. To look -- maybe this should have been on the earlier panel but, the

LOLE planning process in a way is almost like legos and the basic break is this analytical technique that says for a given week of the year if you have this much capacity, what's your chance of loss of load?

You add that up across the year you get your annual LOLE and the planning process to over simplify comes down to iterating through how much capacity you have until you find the amount that does what you need.

What's nice about that flexibility is that it is very amenable to take some here and put some there and so on and again strictly for planning purposes. So the planning process I think is both amenable to a fixed allocation and since you're really iterating over all these values anyway, should be able to produce a range of mixes, you know, as I mentioned in what our example was.

You can meet the reliability needs of 170,000 megawatts of annual, 150 of annual and 21 of summer and so on. That is again a pretty, I believe, straight-forward thing to do at the planning process.

You then have to -- if you do go with the forward dynamic allocation which we think is best for cost optimization, you do get a more complicated option clearing right? You do have a couple more degrees of freedom to optimize which is actually the goal right?

The more freedom you have to optimize the better the results. I'm not being an optimization theory expert so I can't 100% say that it's possible but I compare the complexity of doing that a few times a year to what's done in the energy market every five minutes and it seems like we should be able to get to some solution.

And then finally Stu again, Dr. Bowring already had mentioned operational challenges -- that there's suddenly a vast influx of demand response and so on. And it would seem -- well first that we know how much command response is out there. We'd be sort of surprised if an extra 15,000 megawatts popped up one year or another.

And it would seem fairly reasonable to come up with some kind of transition rules that when things change gradually so we don't get any sort of transition shock if that is a real operational concern, thank you.

MR. MONICK: Yes, Dr. Shanker?

DR. SHANKER: Yeah, Tom, so everybody is clear that your definition is -- of this seasonal CP product is different from Steve's as well?

MR. RUTIGLIANO: I think we're speaking at a high enough level here that I'm not sure of inbound product definitions but for working model I will say it is the same obligations as a resource of the same technology over a defined period of time.

DR. SHANKER: Okay, so wind is comparable, the wind but not the solar demand response?

MR. RUTIGLIANO: Again, to the extent that it exists in CP now.

DR. SHANKER: Okay, so this is -- this is the moving ball okay? Let's -- we had status quo to some extent -- I don't want to put words in Jim's mouth but that's what I heard. Okay, then we had CP 24/7 that I asked explicitly and now we have well I have things that don't have to operate at night or are when the wind's not blowing, but they're exempt from CP.

And forgetting even if we do that how we model -- you can't really do it by distributional things as the say we do with prism, you'd have to go to some sort of Monte Carlo approach. Right now you're looking for another set of exemptions and you say but it's all the same product, its' all CP.

And I mean this is where you've got to slow down and say they're really not the same product. They're not the same availabilities, they don't behave the same. They have systematic failures, they have systematic properties -- we don't want to call them failures in terms of availability and we're saying but it's only a little bit.

And so if I set it small enough is that going to be a problem? And so we've done that before and we've gotten in trouble before by doing that and I thought one of the strengths of the order on CP from the Commission was the acknowledgement reasonably directly, of an annual CP product that homogeneous product, that was going to be used across the board.

And as you're listening now that's three different definitions we have. If Joe offered one, I think I agree with Joe's from this morning. I don't know if I remember -- I think Stu and I would agree on what the definition is.

And we want that, it has a lot of good, strong behavioral properties. If you could get everything to be identical in those properties so they really are black boxes with megawatts and forced outage rates -- then we might have a hope of approaching a seasonal market, if they were truly homogeneous.

And even then I would still offer cautions. At the moment we start saying well I have 10% of those that are never available at the same time because of wind issues. They're never available at night but they're CP because we don't think there's a high probability that the peak will come at that time.

But then we have the predicate of the entire pricing offering, being that you're doing an opportunity cost calculation on the likelihood that you're not available when one of those performance hours occurs.

And it isn't necessarily a generation performance hour. Most of the things that are caused are locational and I'll defer to Stu as to the split between generation and a locational basis versus distribution transmission. I don't think I have a good feel for that.

And so it does -- suddenly all these fine points of definition that everyone's waving -- make room for my summer product which is what this is really about. Suddenly BIM's are very, very important. How do we set the demand curve for 9 comparable products that you just defined to be the same for half of the year?

We had some gross notion from Sam that we can partition it on marginal contribution LOLE but it will be interesting to see how he does that when I started asking about, well, you know, those aren't really homogeneous products, how are you going to talk about marginal contribution when you don't have all the nice distributional statistical properties to do that and so maybe you have to do large Monte Carlo simulations over huge amounts to catch what's going on and maybe you can do that.

You know, in the abstract I'm a modeler from forever so I like saying of course we can model it. But you've already heard different product definitions, no solutions in terms of the notion of trade-offs, don't worry it's not big, and you're seeing things that cut against the outstanding benefit of the Commission's accepting annual homogeneous because it did away with all of these problems, okay.

And we didn't even get to the notion of how do you make people whole -- because ultimately I think one of the catch phrases was retain and attract was in a number of Commission orders with respect to the function of command in the capacity markets -- retain and attract that's what we want.

We want to retain existing generation that's economic -- we don't want not economic. We want to attract that. None of these we've talked about -- the make whole function of the capacity market that Joe mentioned is being a complement.

The capacity market makes the energy market work in our design. All of those things are still missing and those are all -- you asked pieces of what we need to do. All the things I said are tasks that have to be resolved.

MR. MONICK: Let's take two more comments and then we'll have a break.

MR. LIEBERMAN: Thank you, Steve Lieberman with AMP. I appreciate Roy keeping score there for everybody on a number of different proposals. No you kicked off this first question asking are there feasible alternatives to PJM's current practices?

I didn't hear you say what is the best -- is there only one? Are there feasible alternatives? And I think what Roy just highlighted is yes there are. They all have their challenges, that's true. Some have more challenges, some have less, some are going to be easier to implement, some are going to be a little more difficult.

But yeah, Roy's a smart guy but so are the rest of us, you as well and the folks sitting behind me. We're all pretty smart and I think if we have an idea of what we're looking at -- looking to shoot at, you know, we can come up with the rules and people who can do the modeling -- and I think we can come up with something that works, it's just and it's reasonable and it takes into account what we have in our system today, what's in the queue for tomorrow and the years ahead.

So I wanted to bring this back to your first question which is -- are there feasible alternatives? And I think unequivocally we could say yes, thank you.

MR.WILSON: Yeah, James Wilson. I've already observed that the tariff already defines summer period capacity performance resource and the winter period capacity performance resource, so there are already eligibility requirements for the different types of resources to qualify that.

In addition, capacity performance has very strong performance incentives -- performance penalties for resources and in fact we have seen that a lot of resources that qualify to offer as summer period or as winter period resources, choose not to probably because those performance penalties are strong enough that they don't feel like they can really live up to them.

So it's already there to a great extent thanks.

MR. MONICK: Thanks everyone, think of good things to say after we come back and I'll see you in 15 minutes, 3 o'clock, thank you.

(Whereupon a brief recess was taken to reconvene this same day.)

MR. MONICK: Alright we are back. I'm going to ask my colleague John to ask the next question.

MR. RIEHL: So I would start off this portion of it with a question that kind of gets at the money issue. And I would like all of you to comment on this if you wish.

In the Brattle Group's pre-Technical Conference comments they -- and I'm quoting from them, "We estimate that a seasonal capacity market could reduce societal cost by approximately 270 million per year on a sustained basis. Savings could increase over time as the market evolves based on the opportunities presented, but there is substantial uncertainty surrounding the nature and quantities of participating resources and their costs.

By adjusting their assumptions within a reasonable uncertainty range, we estimate that societal benefits could range from 100 to 600 million per year." So I have about two and a half questions on this.

Do others on the panel agree with the Brattle Group's testament of societal savings? If yes, under what conditions would those savings increase year over year and if you disagree would there be societal costs? Like I said, I'd like everybody to comment on that but Mr. Newell will start, please.

MR. NEWELL: Sorry I thought your questions were primarily to everybody else, whether they agree. I'll say I agree. But I do have to qualify -- I do have to qualify that any calculation like this is a swag right -- we don't have a lot of observables to be able to say it with a lot of accuracy. But every input, every assumption is grounded in something empirical and I think it gets the overall shape of this about right which is that you know, you can quibble about the amount of maintenance you need, call it winter needs, you know, 10 - 15 gigawatts less than summer needs.

There's a fair amount of summer only capacity that we've seen is -- has offered in the past that did not in the most recent option. And there is a fair amount of winter only capacity that could be liberated.

Now I appreciate Tom's point earlier today that you need to get them, you know, show that there's enough transmission to get their additional winter rating out. But if you had that, there's all this winter capacity too.

So there's winter only capacity to liberate. There's summer only capacity to liberate and then there's an overall lower need in the winter and so we've attempted to quantify what would be the cost savings around each of those pieces.

MR. RIEHL: Thank you but I'd like to go down the line and then we'll get people who have their tent cards up.

MR. LIEBERMAN: Thank you, Steve Lieberman with American Municipal Power. So look, I guess a couple of things. One, you know I read Brattle's pre-Conference report. I recall seeing that very same line and, you know, okay, well that looks like there's a lot of money there.

I don't know how the analysis was done so I'm not sure of all the inputs but when I think of societal savings, I think of that as better health you know, is the air cleaner? Are we doing more with less -- these sorts of things? Are we relying, perhaps, domestically instead of importing things and those sorts of things which you could attribute different dollars to -- it's not a, you know, true calculus, it's estimates and I think that explains why there's such a range in the Brattle report.

So I would agree that there's probably savings to be had through the recognition, accommodation of seasonal resources, particularly the seasonal resources that we're talking about which are, you know, whether it's solar, wind, hydro, PV, battery storage, you know, DR, there'll be savings that you know, we could recognize and I think they would be, you know, recognized year to year so they wouldn't just be one lump sum and then we move on and we're back to square one.

But you know, without the benefit of having seen the math and the models, you know, it's hard to agree whether it is 100, 270 or 600 million, but I would agree with the statement that there are savings to be had, thank you.

MR. RUTIGLIANO: Thank you, Tom Rutigliano, AMA. We certainly agree overall with Brattle's results. Our analysis tend to put it a little bit more at the higher end which is based mostly on looking at how previous auctions with seasonal products have fared -- that's that Brattle's has impressive analytical capabilities so I wouldn't care to contradict them.

So to the second half of your question, I believe it was what would improve this moving forward -- you know, we would see perhaps working on cost allocation ultimately because to some degree the way these costs filter out the load doesn't precisely match which how they're created.

It will be interesting to see how the resiliency docket works out because I believe some of the things we told to the capacity market now fall perhaps more into resilience than reliability so a clean separation there could lead to more cost savings.

And those I think would be the primary two areas. I think you could see even more benefit moving forward.

MR. BRESLER: Thanks a lot, I already warned Sam that I was going to quibble with this study so he won't be surprised I don't think. But yeah I don't know enough to know whether I agree with the calculations or not. I'm in a similar boat to Steve.

Obviously I haven't seen the underlying analysis. But just a couple of things on the input assumptions -- I think as Tom Falin described this morning the assumption of a 13,538 megawatt reduction in winter reliability requirement I think is overstated.

I think to what Tom had indicated earlier when you include some refined assumptions around maintenance scheduling and forced outage placements if you will, you get sort of a much smaller number than that. The Brattle number for winter capacity -- so additional, I think capability on thermal units given increased performance during cold weather of 9,500 megawatts -- we're not sure what the basis of that number is. We don't really know where it came from.

We get a significantly lower number based on what comes into us through the GAD's data system, now recognizing generators aren't really required to give us what their actual best number is. I realize our number isn't accurate either but again, I'm not sure where the 9,500 megawatts came from.

We think that the value of 5,500 megawatts of additional summer only could be overstated because we only had 1,200 megawatts of summer only capability that offered but did not clear in the last RPM auction, so that's probably a little large.

And then last but not least, there was a number of 17,692 megawatts of what I believe was additional summer only replacing annual capacity. I'm not sure where that number came from. But really I mean, if what we have here is a sum of all of these numbers, you're getting up into the 30-40,000 megawatts of seasonal resources that would displace annual.

And this gets back to the concern that I expressed earlier where at least qualitatively when it comes to the stability of the capacity market, you know, a lot of what we based the movement to a sloped demand curve, the three year out procurement process, all those sorts of things was the stability of the market in getting away from this boom/bust cycle where you know, you had prices that were moving all over the place when you were a little bit short and a little bit long.

I get concerned about the stability of the resource mix and kind of what clears year in, year out and what that means for the long-term stability of the market and therefore long-term costs.

So I don't know the answer, but I don't think we should really consider going down this road unless there is some level of analysis on what this means -- not just for short-term costs because as Tom said, if you get seasonal resources coming in and you therefore have less annual, you could have prices go down. I don't think that's necessarily a good thing but you could have cost savings in the short-term. I don't know whether they will persist for the long-term.

MR. PLACE: Thank you, yeah I'm sure that we can all note that we haven't looked inside Brattle's black box. But as a first order of calculation Sam said its swag, its back in an envelope. I can't disagree. I think looking at the pieces as they elucidated -- I'm probably inventing a language.

But I think the signal is right. I think that we can quibble about whether it's 270, it's 130 or it's 500, but I think the logic behind it is rational and thinking about the stranded cost loss here, it's not logical to think that it's in the right order of magnitude.

And also from the state's perspective, we've invested heavily in renewables, AMI technology, DR, none of that is getting to the monetary compensation that it otherwise could have named -- this clearly speaks to that -- the magnitude of that issue.

DR. SHANKER: Well I'll agree with the swag characterization. You know, it's the typical -- not only everybody has to do and this is not a criticism, you freeze everything. And so any statics evaluation like this it's worth the assumptions and the assumptions in this case are very broad.

And by definition they're directional because you're assuming there's a surplus. The only thing the numbers that Stu raised is doing some back of the envelope, that 9,500 looks out of line to me, but you know, these are all empirical things that if you wanted to do the statics better we all sat down and the statics, what is it we could come up with -- the numerations of those and the properties and try and see how well they match together and fit the criteria.

So short-term you would say this, you know, this is the kind of ballpark you're talking about. One term -- I look at it a little different than Stu but I think it's just terminology. I think about it as we've designed the system with a -- it revolves around the business cycle to create a feedback loop.

One of the things if you go back the first principles of why do we have the demand curve, and why do we have the shape of the demand curve we do and actually Sam's firm is opining the back, getting it back to where it should have been from the very beginning is that you -- when you go long, we have that sort of flatter tail on the curve and it says, oh, you're not worth nothing, there is something and it will climb in value slowly to keep you both from exiting the market too quickly.

And then when you're short we get it steeper and you get paid quicker and that's as we need something so enter. And that effect is it tends to have people enter and exit and oscillate around the target reserves and all of this is a function of the shape of the demand curve so you think about it as a controlled system -- if you think of it that way.

And I don't know how the control system operates under these circumstances and it's a very and as Stu's saying stability and too much of one thing and PJM through the work of Ben Hobbs, when we were thinking we had a homogeneous process product, was able to simulate some of this.

Some of their performance criteria were things like -- I think it was like 100 years or 25 cycles of 100 years or something like that. And its' how often did you cross the IRM -- that is how often did you violate and solve reserve margins? And Jim is going to tell you why it was wrong and he did it another way.

But how often did you go more than 1 or 2% below? How long were the business cycle durations? If you wanted to look at the 50,000 foot metric of if you try something like this and you accomplish all the tasks that I talked about before and I think Joe Bowring mentioned, and you got them all done, to me remembering that the idea is to retain and attract new entry is how does that control mechanism work?

And I think you can get one -- I'm not going to say you can't, but I don't think -- I didn't read anything there to tell me I know how that control mechanism works and I know how to scale it and I know how to control it to get what I want in terms of Stu's definition of stability when we're all done.

And presumably the objective function if you wanted to put the time and resources into it, of an exercise like Brattle is doing, is to develop the information and figure out okay, I got all the pieces, I think they fit together, now is there a way for me to figure out if they oscillate in a reasonable fashion so that I don't sink the ship by over-procuring or getting, you know, over-damped would be the word in control theory, would that happen?

So in terms of the underlying question about benefits, static, short-term I agree with you, there's a surplus. I don't know how big it is so and if you, in terms of the dynamics of what you're doing and all the things we have to do, I don't know.

And I don't think you can know now.

MR. WILSON: James Wilson. I too, have examined Sam's work papers so I can evaluate his analysis. I actually expected a little bit larger number and when I did an even much simpler analysis a couple of years ago I got a bigger number.

But what I want to mainly talk about is you know, any analysis like that it's compared to something. So what's our status quo?

We don't have a price signal about seasonal resources. Within that aggregation, you know, maybe there's a price that is not transparent that's being agreed to, it's distorted because of the requirement that summer equals winter.

So the but for is like a mess in my opinion. There's no price signal guiding the further development of summer capacity resources and winter capacity resources so under Sam's analysis, he's got a price signal and that is really important over the long-term and from an equilibrium perspective.

So let's keep in mind that PJM in its capacity market, there are a number of different zones and they all have different summer and winter peaks. And for instance, New Jersey has one of the largest ratios of summer to winter peak and New Jersey is also a place with a very large amount of solar potential.

So if solar were to develop very quickly in New Jersey, would we actually get to a point where we had, you know, enough solar so that it was like almost too much? Well we need a price signal to tell us that. You know, right away the question would be more summer resource in a zone with such a big ratio, the value is all in the summer for sure. But we could get to a point where we need a price signal to tell us, alright, slow down on that.

And other zones will have different situations, so you really need that -- seasonal price signal to guide the further development and how to evaluate the value of that compared to the status quo where there's like no price signal at all -- well it's hard to imagine how resources even develop under that but for, so I don't know.

But I think the benefits are large, thank you.

MR. GRAMLICH: Well since I actually did my homework, I've read the study on the Metro coming over so. I thought the framework was sound. I thought it started with the basic idea that you do have two different products. You have different supply sources available to provide one and can't provide the other and vice-versa which is I think, pretty much, the definition of different products.

So we're going from an incredibly crude system of one product to two products which is two out of really there should be 8760 and in fact, we have a market that already does 8760 times the number of nodes. So to say we're going from one system-wide to two and call that overly complex I think is absurd.

So theoretically that sounded and then I think the study went through each resource that's available to provide each of the products -- the summer and the winter product and I thought they were generally sound.

I know in the wind case it basically said well for all of the 664 megawatts that for some reason are not participating which as I've described in the WEA and Merrick comments, talk about some of the barriers to entry and the penalty structure problems, but these, you know, these resources are available, they could provide and it's somewhat mysterious why sometimes they're not.

The same is true for some solar and other demand response. We should be looking at demand response -- all the barrier to entry. So it's a long way of saying that the study assumes these barriers to entry are removed and the cost savings accrue to customers once you remove them and I don't think we should just assume the barriers are removed, we should actually remove them.

So but if you did that then I think the numbers are generally in the ballpark. I would -- I noted Stu and Tom Falin mentioned the -- on the winters a lot of talk about winter versus summer LOLE and you know, we should be able to figure out and agree whether planned maintenance can happen in the winter.

I know a lot of folks in this proceeding are talking about the scenario 5A that PJM with their updated reliability analysis says oh we should be able to, you know, do the maintenance in the winter just like the summer.

Well let's just agree on that and figure out what the right answer is. I mean if Stu's operating the system and he can't do it in the winter then that's where I would start and you know, that would lend to greater capacity value in the winter of course, so.

DR. SHANKER: May I ask -- this is a clarification from Rob? I think maybe two things are mixed or maybe I heard them mixed in my head. We're talking about wind not participating because of risk and I assume you're talking CP risk?

MR. GRAMLICH: Yeah.

DR. SHANKER: Okay. If wind is fully qualified as a -- and it is as far as I know, as a -- being eligible to be a CP product in -- are there specific elements that you saw in any of the proposals that would remove that risk?

MR. GRAMLICH: Well I don't think penalties are explicitly addressed in these proposals.

DR. SHANKER: Okay, so you're -- okay so let's try again. So CP stayed the same and we had a seasonal problem. A seasonal product -- your problem would remain?

MR. GRAMLICH: In part.

DR. SHANKER: Yeah okay, that's -- I thought I was hearing that it would go away and that was confusing me, thank you.

MR. NEWELL: Thank you, can I have a turn to respond to some of the comments? So one kind of threshold issue we've talked about today is what is the winter need? Now peak load is about 20,000 megawatts lower but there are some winter challenges and maybe you have to do a little bit of maintenance in the winter so I don't think anybody's saying you can pick your 20,000 megawatts less in the winter, so what is that number?

And we went with scenario 5A. That was with no maintenance in the winter. Now that -- let me back-up to what scenario 3A was that was with the average historical maintenace during the winter and you could still have 9,000 megawatts less in the winter and have only a tenth of the annual reliabilty events in winter.

So, 3A used historical maintenance in the winter and that means when somebody wants to do maintenance they would come to PJM and say can I do maintenance now? Things weren't tight so the answer was probably yes I assume.

Now in the future when things get -- if things get a little tighter, maybe the answer would be no, don't do it in the winter if there's enough room in the summer and fall, in the fall and spring. I don't know, but we could figure out I agree.

Should we be in scenario 3A or 5A? But I think it's one of those. As for all the issues that were mentioned that were not included in the analysis, I think they actually were included in this analysis. Now correct me if I'm wrong, but I believe that this analysis that had these scenarios did account for correlated outages in the winter.

I believe scenario 3A did account for maintenance in the winter. And the only thing I heard from Tom that is still working out is some winter load forecast modeling issues. So I think these scenarios that are consistent with your intuition that you don't need as many megawatts in the winter -- one of those is probably right but again I would like PJM who did the analysis to correct me on any of those.

So that's one. Another one was winter capacitiy ratings are higher than in summer on particularly combustion turbines with the denser air going into the compressor. The combustion turbines can do about 12% more in the winter than in the summer and that's a fair amount of the fleet including what's in the combined cycles.

And the coal and nuclear units are a lot smaller, more like 1 or 2% more. Our data source was from the Ventix compliation of I bleieve it was EIA 411 if not 860. It was one of those FERC forms and it aligned with what we know about the technologies there.

As for the 17,000 that could be, you know, not firming up in the winter, that was just recognizing hey, if you've got -- if your winter requirement can be 13,000 megawatts lower plus you've got 10,000 megawatts of liberated winter capacity, you need a lot less annual capacity.

So that liberates some of the summer only DR but it also says hey, even some of your annual generators don't need to constantly firm up for the winter -- that's where the 17 -- you know, we didn't have very large cost savings associated with that but that's where that assumption came from.

And maybe that's -- I'll leave it at that, but I think there's one other sort of high level point that is lurking here which is -- so what happens if you tighten? So I think in general we've expressed is if you more precisely measure what it is that you need and you more precisely characterize it from the resources, their ability to meet those needs, you'll get a more efficient outcome from the market.

And again I agree two products compared to, you know, one compared to the 8760 that it is in ERCOT, you know, it doesn't worry me that much even though I hear Roy's warning about making it overly complex.

So -- but is there a down side to tightening this when perhaps right at the same time we're talking about resilience, you know, and we say well maybe you don't need as much in the winter. And, you know, it could in fact, cause some annual reserves to retire if you did a seasonal approach that fully recognized the needs and the resource capabilities. Is that a problem?

I'd say so make sure you're defining the winter need properly -- you are getting enough megawatts and then you use capacity performance incentives and energy price formation that rewards contrarian fuels and scarcity pricing to provide the signal to provide the quality of those megawatts and meet the resilience needs.

So I think the question is, you know, I'd say yeah, we should tighten down the specifications and procure resources more efficiently -- you know as efficiently as possible in this market. The question is whether you trust that construct. Are we going to have unintended consequences?

Do you trust this construct and do you trust PJM's ability to model all of these things that we heard this morning that are difficult to model? And if not, what do you do about it? Do you procure a lot more megawatts as if winter peaks were as high as summer -- is that the right solution or is there a better solution?

Mr. lieberman: Thank you, Steve Lieberman with AMP. I'm not sure if I heard Stu correctly when he was questioning where the 17,000 megawatts came from. We've talked about -- Sam just mentioned table 3A and 5A and on and on and on but those are available on PJM.com. That was analysis that they did. It wasn't anything that anybody at this table perhaps except for Stu did.

So it's important to point that out that these aren't numbers that we cooked up and are trying to sell, we got this data from PJM at our request and we were appreciative and if, upon further reflection, PJM thinks they've made some computational errors, that's understandable. We all forget to carry the one every once in a while.

But it is their data, it is their values and that's all that we have available. On the dollars, we were asked about the Brattle Group and you know, besides the Brattle Group the Market Monitor does a sort of a post-mortem after the BRA. It does a number of scenario analyses.

And in those scenario analyses, some say, you know, if this -- if this had occurred what would the clearing price have been or moreso what would the total dollars that would have been expended for capacity -- what would they have been?

And I'm looking at the comments that AMP direct and ODEX submitted for this Conference so I apologize for looking down but I can't remember my phone number and there's more digits here than in a phone number.

But for the 2019-20 RPM one of the cases they looked at was if there was no base capacity resources or base capacity DR in the E and everything else the same -- total RPM market revenues would have been 75% higher. So roughly 12.2 -- I think that's billion, an increase over 5.2 billion.

So we can see that if you have, you know, as I think of it that's a better argument, it's efficient. For the 2020-2021 that Michael Meyer did a number of analyses as well and looked at what if there had been no offers for a demand response and energy efficiency.

And again the RPM market revenues according to the Market Monitor's calculation would have been higher by roughly 1 billion dollars and we know that that's a little over 15-15 % increase so. There's a lot of dollars that node would have to pick up and pay but for using efficient resources that are in the marketplace that we could accommodate through some changes.

MR. MONICK: Thank you, I believe it's Dr. Shanker?

DR. SHANKER: Thanks. Actually Sam's comment I think gave me a logical example of what Stu was trying to say about what I was trying to get through about stability. I agree with first off if we had a couple of years or more I think we could approach what you're doing.

And if we tighten the system, presumably there is efficiency. If you tighten the system, the predicate is a significant amount of that is DR. Presumably it's not going to be offered at the system cap, there won't be an emergency resource where you get into the loop that Joe talked about.

And as the frequency of calls go up, the participation rates go down, or the risk of CP penalty goes up and you start to oscillate between people that don't have extensive capital entering and exiting the market and it becomes reasonable.

I know the whole CP design is you -- your offer price is a balancing of you get paid CP but if you're not a CP resource, if you're available during the CP periods, PAH periods, pardon me.

So if there's a performance assessment period you'll get that payment whether you're a CP resource or not. So you don't have to participate to get paid. Right now we don't have any thing so the system has been long and this is three years that we haven't had any -- something like that so we have other problems calculating things because we don't have them.

We tighten the system down and we have people who are used to bidding at the cap which I think would be one of the first behavioral changes that I would expect from PJM that you would see economic offers from DR.

And suddenly they don't want to be called that often. We heard that this morning. I don't want to participate. I don't want to be called. I want to get the capacity payment and sit there. But as soon as they get into a mode where there's any economic performance based on the CP risk starts to escalate. And as soon as that escalates, because there's not a lot of capital to pull out of the market.

And this, I think is what Joe was getting at and what Steve's getting at and what I'm worried about. It's these kinds of -- it sounds real good and I have the statics here that tells me what's going to go on and the minute you go to the dynamics you say oops.

And this it seems to me to be a very predictable oops. I don't know -- no one is going to sit there presumably and allow 20,000 or 30,000 megawatts shift to summer only and bid at $2,000.

I mean you can do that, but I think we'll be back here again. We'll be doing something else like that. And the moment that that gets adjusted the call rates change and you get into a PRD type environment with the calls going up and then the CP risk goes up and then somebody sits there and says, I'm better off not being a CP resource and sitting back and waiting for the PAH hours because the emergency calls in DR or PAH hours and if I'm available I'm going to get the money anyways.

But then we have less firm resources and we need to send the signal to attract others. And it's that kind of a loop that I'm worried about. And it's not hard to visualize. The ones that they are disturbing are the ones that take two years to visualize after the fact and realize that you've seen it.

And this is what I talk about about the conscious. We've just been sitting here and talking about it for an hour or so this morning and we can start to articulate a bad cycle and a whole bunch of rules that go with it.

MR. RIEHL: Thank you and forgive me I didn't see who put their tent card up first of the two of you.

MR. BRESLER: So first of all I want to express appreciation to Steve for his understanding of a potential arthritmatic error. That is not what I was trying to refer to with respect to the assumptions. I'm sure that our folks did a bang up job on the analysis.

What I was trying to convey was just because every single -- you know there is a certain amount of megawatts that you can assume with respect to these analyses, I'm not sure how rational or how reasonable it is to take every single one of those megawatts and put it into one of these benefit's analyses, so that's what I mean when I said I don't know where the number came from that was used in the study. Obviously the numbers that are posted on the websites are sort of are what they are.

So yeah, like I said, I don't know how sort of, close to the mark, you know, the short-term savings analyses are. My point is I think the more important thing is the longer term analyses an Roy already articulated that again so I won't do it again.

But I did want to just to make sure because Tom had referred to my concern with respect to the potentially significant increase of demand response that would need to participate economically as really an operational concern. That's not really where I was coming at it from because you know, we've been prepared for the dispatchability of demand response for some time given some routines that have occurred in the past.

My concern was more along the lines of the potential for those types of resources to come in and out given all the risks that Roy referred to and the need to respond when again that's not the business they're in of responding like that, so that's kind of where I was coming in with that concern from.

MR. NEWELL: Right, I mean, I agree that the system will continue to have challenges that kind of make Stu's day-to-day very interesting and probably even moreso if we tighten everything in the market, right?

But I think in general you can do better if you make the expression of needs more specific around each season and you really carefully characterize what should be the rating of each resource and how to qualify each resourced, you can deal with these kinds of problems better actually over time.

And as for DR, I mean that -- don't let Roy scare you. I mean the thing is DR -- about 10% of the peak load occurs in 1% of the hours, you know. This is a natural product to have a fair amount of it.

And it's not just DR. It's -- it's other resources that we're getting more of that have a seasonal nature to them -- solar, wind, it could be seasonal imports. I mean so, it's really not even just about DR.

Can I respond to one other point? There's been a little bit of confusion about comparing our savings estimates to other estimates done in PJM's or the IMM sensitivity analyses after auctions what would the prices have been with more or less DR?

There is an analysis Jim did a while ago -- I just want to be clear these are very different kinds of analyses. Those analyses had to do with you reduce demand the price goes way down and that saves customers money.

It's actually a largely transferring money from generators to customers. That's not the nature of the calculation that we did at all because I'm always very, very weary of trying to justify a change in public policy or market design on the basis that it effectuates a wealth transfer and then hope that that market continues to, you know, be a customer's benefits. That's not the kind of calculation we did at all.

The benefits that we estimated were simply you are liberating some low-cost resources that are stranded right now and buying fewer high-cost resources. Not the price, just you are buying fewer resources that cost whatever is the capacitiy price -- the cost of capacity, $120.00 a megawatt day, buying a little less of that and a little bit more of low-cost resources that are liberated.

MR. RIEHL: Thank you and then Vice Chairman Place?

MR. PLACE: Yeah, just briefly. So to think about the first principles, yes it's not trivial to think of how to characterize and how to qualify units but from my perspective the market is more stable the greater participation you have.

The larger the end the more stable it is in handling and for when I look at what we're thinking about the rationality of bringing in more participation that is one of the significant drivers for my consideration of this and the value of what we're thinking about.

MR. RIEHL: Thank you and then I believe it was Mr. Rutigliano?

MR. RUTIGLIANO: Thank you, Tom Rutigliano, AEMA. So just to address some of the comments you've heard about how DR might play out in a reform capacity market and I think some broader concerns too at about long-term price signals.

I would agree with Dr. Shanker's -- his analysis that you know as we tighten up the market and if more of it comes from DR you probably will see demand response being called more often.

I think what I would consider somewhat unrealistic, or even preventable is that could happen catastrophically quickly. You know I think the reality would be more that demand response continues to grow, it starts getting called more which makes it less attractive and harder to demand response participants.

And you would potentially have some year-to-year up and down but ultimately that's how you achieve the equilibrium level of DR in the market is, you know, by a balance between the pay-offs and the responsibilities being demand response.

And ultimately the market I think is pretty well served by having a group of resources that are low capital and price sensitive -- that gives you kind of a crucial buffer in your capacity market.

Well maybe the deeper question to this is are we afraid of a radical long-term price signals and what's our kind of long-term planning out come from this -- which I feel dovetails into these almost national energy policy conversations that a capacity market might not be the right tool to resolve.

I mean to venture a little far and few, if I was sitting in Stu's chair yeah I would worry every night, you know, retiring a nuclear fuel because of a few years of cheap gas is a good idea. You know there's a lot of those kinds of questions coming out of the capacity market but if we are constantly tweaking the capacity market to deal with the planning problem of the year, we risk moving away from a market that's procuring into fine product or something whose point is to achieve reliability and it ends up just becoming a particularly opaque subsidy mechanism.

So I think there are some hard questions certainly above my pay grade to think about how do we do long-term planning in a market economy -- you know, deregulated market? Do we have national energy security concerns at these capacity markets are not addressing and so on.

But I'd just submit that those maybe problems that are not solved through trying to design a capacity market that achieves the outcome you hope to get.

MR. RIEHL: Thank you, Mr. Bresler?

MR. BRESLER: Thanks. And I think Tom and Sam between the two of them raised a very interesting point and that is sort of the environment we're in today sort of with all the concerns that have been expressed about resilience.

And I certainly would not be anyone to suggest that we should overprocure because we have those types of concerns but on the otherhand I think it does point out that you need to think extremely carefully about these kinds of questions. If what it means is that we are going to again drive the annual resources out of the market in favor of other types of resources and then what that means for the longer term.

So I just -- I believe that as a question. I believe with Tom it's a very big question and Sam as well. The one thing I did forget before I gave up the microphone the last time is I do feel like I need to stick up for Dr. Bowring a little bit because I fear his analysis of the impact of demand response and energy efficiency in particular, summer only demand response and energy efficiency is where he gets mischaracterized.

Because I think as he said earlier today and I just felt the need to remind people -- what he was pointing at in that analysis is the price suppressive effects of the differing products and the seasonal again, replacing an annual resource.

So that was what I think was the intent of that analysis. It was not to say that there's a savings associated with having those resouces so I felt the need to -- in my conversations, that's my understanding of the point on analysis and I felt the need to point that out.

MR. MEAD: Can I follow-up, at least partly related to your point. With regard to whether we need two full seasonal auctions or we can procure summer and annual at the time time in the same auction, I mean in the case if you have two full seasonal auctions and the products are comparable, then the auctioneer picks the lowest cost or the resources that offer the lowest.

And clearly that's the right economic decision. On the other hand if you have two auctions -- if you have one auction that's procuring both resources, it's not clear that if you pick the same and pick the lowest cost set of resources that you're necessarily getting the right mix. How big a problem is that?

DR. SHANKER: We've had this before I mean we had this with the process that PJM implemented before and different products that were, you know, extremely different but I felt the partitioning for quantity was arbitrary and the price impacts were not thought through.

They were and this is where Joe's analyses, Joe Bowring's analyses become very important is that we're significantly price suppressive for extraordinarily different products and they go to my point that you can solve anything, you can just throw those equations in there.

And first implementation -- don't have less than "X" and I think it was 90% whatever of the good stuff and then you can buy as much of the bad stuff as you can out to the demand curve, okay?

And everybody will yell at me but then the equation's got reversed. It said don't buy more of the seasonal stuff -- let's put it that way or the summer limited and then let the other products run out to the demand curve -- the annual products. Prices were significantly different -- you can look at the spreads between them and the total cost impacts for material but the unifying principle is I look at them and the difference in the price differentials and the marginal values were nonsense.

And so yeah, it is a big deal. You have to understand what you're buying and you have to understand substitutability. You have to understand whether or not you're really buying using the remotely resembles the product, not simply that you can put it into the optimization.

We've experimented with that and Joe will give you the web address, there's one of these for every year and you can take a look at the clearing prices, PJM also. PJM does it different, Joe does it by hypothesis of product, whatever PJM says. Assume "X" megawatts more, "X" megawatts less.

But they both have a set of these reports and if you look through the periods when there were multiple products and you could make sense out of the price separation I'll be impressed. I don't find the consistent story for any of them.

MR. LIEBERMAN: Steve Lieberman with AMP. So we keep talking about the price suppression and it confuses me earlier panels made comments about how they think that's a mischaracterization -- it's not a price suppression, it's efficiency, market efficiency -- doing more with less and that's exactly what these results are showing.

Roy keeps talking about -- and I should preface this by saying I'm not a DR expert, I'm far from a DR advocate, I argued in the past that DR should be on the demand side and not the supply side but it is where it is so we have to deal with that and that's okay.

But we talked about degradation and DR as you call on it too many time, fatigue -- whatever word you want to call it. But the same is true of generation as well. When generators run full out in the summertime heatwave, they degrade. They have to take time out and do some maintenance.

And we understand that. It's part of the way they work, yada, yada, we get it and at some point in the system after the summer we say, okay, we have to take a step back, we have to tighten the nuts and the bolts in these sorts of things and we understand.

But the parallel is the same that when you use something a lot it degrades, whether it's demand response or generation, thank you.

MR. WILSON: Yeah, James Wilson. Let's be clear about what Joe Bowring does in his sensitivity analysis. He yanks the DR out and then he resolves the auction and he gets a higher price.

Well anything you yank out and then resolve you will get a higher price so you can accuse every generator that offered into the auction of price suppression. But really to talk about the impact of DR or of anything else, you have to look at it from a dynamic perspective.

So if that DR wasn't allowed, what we've seen in PJM is there's an awful lot of new combined cycle capacity coming along in the pipeline so we've done all sorts of things over the last ten years. We've kicked out DR, we've kicked out imports, we raised net cone, we eliminated the market power mitigation, we've done all these things that should raise capacity prices and they haven't -- why? Because the prices are generally set by combined cycle entry.

So he's not really evaluating price suppression compared to DR -- due to DR, he's just doing a sensitivity where he yanks it out and sees how much the price goes up. If actually people knew the DR was gone, you'd see more combined cycle entry and probably end up in about the same place, thanks.

MR. BRESLER: Sorry just one more. I can't help myself. I guess I need to respond to the characterization of kicking out DR and imports and market power mitigation. We had 7,600 megawatts of annual demand response clear in the last auction plus another 3 to 400 megawatts I think of price responsive demand so that's almost 8,000 megawatts.

And if you look in historic years we have typically about 8 to 9,000 megawatts of demand response that actually commit in any given delivery year. So I think we far from kicked out demand response. Similarly with imports we still have I think 3,000 plus megawatts of imports of resources in the PJM.

I'm on the mitigation on that so I can't address that one but I couldn't let that characterization go by.

MR. MONICK: A question for the complainants. The Commission recently approved the move to CP of the annual product. Have we had enough experience in PJM yet to say that the results are bad or that they need to be changed? Is it something we should be looking at, you know, giving them some time to see how it goes, what are your thoughts on that?

MR. LIEBERMAN: Steve Lieberman with AMP. So do we have enough time with CP -- I guess I could say yes. I could say no, it depends. But what we can look at is the auction results and we can see before CP what did we have, after CP what did we have?

And then even while we were fussing around with CP, you know, we then said well jeez we have to do something about aggregation and that's really what we're focused on here is the inefficiency -- is the inefficiency of the aggregation and that's what we're focused on.

So in our pre-Tech Conference comments we have some stats here about for instance solar resources. So in 2020-2021 BRA solar resources dropped by nearly two-thirds compared to the prior year. So if I stop right there I think that highlights an issue with the aggregation rule.

So we may not have enough experience with a year in which all the resources are annual CP but we can look at how the auctions have cleared and see the problems and we shouldn't have to wait until, you know, two years go by or three years. We should say well there's a problem, we've identified it, let's fix it.

MR. RUTIGLIANO: Thanks, Tom Rutigliano, AENA. When in the first pure capacity performance auction I think we ended up losing about 2,500 megawatts of demand response and amount to solar, that was a small and absolute occurrence but I think large compared to the solar fleet.

So we're seeing the resource types affected already. You know that said, prices were reasonable, the cost of capacity has not sky-rocketed to ruineous levels. I mean I think the load is taking more than they need to, but the demand response industry -- the more years you do this the more it atrophies.

I mean I can say you know, in the commercial merchant demand response states, people are already retrenching and shrinking business plans. I defer to Chairman Place but I imagine it's only a matter of time before states start disinvesting in their load management programs and so on.

So I think there's an accumulated damage to the affected industries. And then in the higher level, PJM is over-supplied in capacity. I think there's you know, we've run what, 26% reserve margins and RPM initially contemplated clearing near the IRM.

Energy prices are you know, so flat that there's very little response to, you know, incentive to manage energies hour to hour. And that over-billed I think comes from some of these capacity market where they are saying price suppression I'll say price inflating effects of restricting these resources. And if we've learning anything from history of markets overall that if you keep an overbuilt market from having the correction, the correction is just going to be that more painful when it comes.

You know so we may be in a place with PJM where there's a problem amongst the managing downsizing, managing retirements which is a scary problem, but that's not going to go away and so ultimately I think the longest term of concern is not the cost to load, not the affect on the DR industry but how we get out of a chronically oversupplied market.

That said, speaking for the AEMA, I'm not going to say that the harm to DR is negligable and ongoing and will become more long-term the longer this lasts.

MR. MONICK: Rob, actually I wonder if I can get your take from the wind perspective?

MR. GRAMLICH: Well I think as Steve said there was a drop-off of solar. I think there was a drop-off of wind, actually we did capacity performance so looking, taking kind of the long view on capacity performance -- I mean I don't think anybody's arguing that changes were needed after polar vortex and the poor performance of certain generators.

But there were, I think, unintended consequences from the changes that were made. I think again, the penalty structure was a problem for wind, I don't know exactly what it is for solar or for -- there's been a lot of discussion about demand response but I think there are some barriers to entry in this market and it's time certainly after four years to say well, okay, so maybe generally that change was the right thing but we need to fix some problems with it and make sure there's eligible entry and free entry for all of the resources that are providing value here.

MR. MONICK: Go ahead.

MR. RAMLATCHAN: This is a question for Mr. Bresler. So during parts of today the concept of outage correlation was raised. Is this something that to understand the risk in the winter better, is this something PJM is still working through or tweaking or do we have -- does PJM have a good handle on that?

MR. BRESLER: Yeah, my understanding is it's still something we are sort of finalizing what our assumption should be as to the input to the LOLE calculation. So I don't think we have a final value on that yet.

MR. RAMLATCHAN: And one quick follow-up, outage correlation -- correlated outages as opposed to common mode failure, does PJM make a distinction between those?

MR. BRESLER: I honestly don't know, it sounds like Roy does.

DR. SHANKER: Yeah, I was going to say that's only half the problem. And you're going to help Stu --

MR. BRESLER: I'll try.

DR. SHANKER: Because I believe Mike Dyson was working on that common gas mode so the common mode failure I think is being at least initially addressed through post-contingency actions -- is that the way they are modeling it? But the frequency -- so that's operation. The frequency of putting it into something like prism is what Tom might be doing but I don't think that they are.

I think that they're doing more correlated --

MR. BRESLER: I'm sorry, maybe I should clarify what you mean by common mode outages. Can you explain sort of what you mean by that and then I can maybe help?

MR. RAMLATCHAN: Sure, so I think others might jump in also. So as opposed to any type of outage driven by correlations and the wind stops blowing. Common mode failure being something different than that, maybe pertaining to an element in the system, whether that be a pipeline or a transmission.

MR. BRESLER: Okay, so you're talking about something that would cause multiple generators to fail at the same time other than just happen to have their outages correlated --

MR. RAMLATCHAN: Yes.

MR. BRESLER: Sort of more randomly if you will. Okay, I'm sorry I didn't know what you meant by that. Yeah, I don't know if that is something that will work its way into the LOLE analysis or not.

I can tell you that we are working on what we should be modeling as far as those types of contingencies. Roy is correct that for the short-term, for the very near term we have said that if we see a single contingency that we believe needs to be addressed we will do so in operations and we have a series of steps we've posted like, you know, requesting generators to reduce their output, to reduce the size of the contingency or if they can switch fuels, switch pipelines if they can do that to maintain their output.

But that's for additional stakeholder discussions as well. Clearly in the mid-term, I won't even say long-term. In the mid-term those contingencies ought to get into dispatch and price like any other contingency, but there are complexities with modeling those types of contingencies in the N minus 1 security analysis and therefore the LNP calculation and that's what we're working through now.

So I don't have a timeline for you when we intend to do that or when we think we can do that but it will be in my mind sooner rather than later. But that's in -- again, the operational realm. We need to look at then what we put in the planning realm, both from the transmission standpoint as well as the resource adequacy standpoint and that is probably more along the lines of a resilience type analysis that we are undertaking.

So we are doing all of that I just don't have the direct answer for you right now as to what, if anything, from that would get into an LOLE now.

DR. SHANKER: I don't think anyone has got it on the LOLE side. The long-standing operational contingency that looks like this is the in city minimum oil burden for New York for Manhattan and they have a common mode failure on the gas NBS trunkline or something. And so as load goes above certain levels the burners have to switch over to oil.

And the things that Mike has talked about it in the similar kinds of things I think all post-contingency. Switching them over into probabilities into LOLE is really tough because these are the low probability, high-impact and they're very difficult to incorporate into this.

MR. RUTIGLIANO: Thanks, Tom Rutigliano, AEMA. Yes so the treatment of these common modalities and the related issue of winter maintenance were I think part of the original justification for eliminating seasonal products and going to the full annual requirements. I think it's worth looking a little deeper into how this all plays out.

Ultimately I think including them in the LOLE studies and raising the required RRM is inconsistent with the pay for performance approach. I mean just to trace the story back when we're doing capacity performance we just come off the polar vortex and there was this general feeling of enhanced risk in the winter that we didn't have a good analytical handle on.

So to some extent I think -- no offense to you, but PJM kind of went with their gut and said, you know, let's keep the winter and summer capacity the same, that should give us more of a winter cushion until we pin these risks down more.

And similarly some generators need to do winter maintenance so again we're going to have more capacity in the winter than we otherwise need to allow this winter maintenance. Those all kind of support the case to say we don't really need seasonal capacity allocation, we'll just do the same all year and we've got some good uses for this extra in the winter.

Now that approach is just inconsistent with pay for performance. In the correlated outages area, if you have some technicology "X" of generators that you feel is delivering less capacity than they're actually UCAP rating in the winter because of correlated outage, and you simply buy more capacity to cover that, you've taken the risk away from that family of generators and put it on load.

You've also put it on summer resources because they've been excluded from the market so you have more supply of excess capacity in the winter. I believe the proper approach is consistent with cost causation is to say that family "X" of generators I'm going to derate their UCAP and again, I appreciate it's not the individual generator's fault but that is consistent with the treatment of out of management control elsewhere and capacity performance.

You get to a similar place with winter maintenance outages, right it's difficult to see how in a construct that talked about no excuses pay for performance and was motivated by winter reliability it's okay to treat a resource that needs to take an outage during winter peak as a capacity resource.

Right? That seems to conflict with the very purpose of capacity performance. You know, so certainly as an operational guy Stu's telling us, you know, we need some winter maintenance and okay, so be it. But if you need to schedule a winter maintenance during winter peak months, you shouldn't be at capacity resource that year or at least that winter if we go to seasonal.

You know and similarly so, yeah I guess I'll just leave it at that. In both cases we've got costs that properly on generators being shifted to load and summer resources because we're out -- we're buying more capacity to cover the fact that generators or I'll say supply resources in general, annual supply in general -- we don't quite believe it's going to deliver what it's rated as a fleet.

MR. COHEN: I have a question. What percentage of the resources that take an outage in the winter know that they're going to take an outage in the winter three years ahead of time? I mean it just seems like it's probably near zero, right?

MR. BRESLER: Yeah I was actually going to finish that thought. It's an excellent point and I just wanted to remind everyone maintenance outages are recallable. So PJM with 72 hours notice can recall a maintenance outage. A planned outage is one that we can't and I think that gets to your question.

So planned outages are extremely difficult. We're very -- what's the right word, discriminating I guess about allowing any planned outage during a peak season. But maintenance outages -- I think we have like a 72 hour recall on maintenance outages.

So I think that's part of the equation. As far as the single common mode failures and the LOLE calculation, I certainly see what Tom is saying as far as bumping up the entire capacity or reliability requirement as a result of that.

But that doesn't mean they shouldn't be incorporated somehow, so I just wanted to finish the thought there. So that's why, that's why I said I didn't know whether or not, you know, we would get to some place of putting that LOLE because I don't know that's the place for them either.

However, it certainly seems like that type of analysis needs to fit in somehow as far as locational criteria or criteria for what it means to be a fuel secure resource that any resource theoretically could compete to fulfull that criteria and then implementing that as constraints in your capacity market so that you have, you know, on a long-term basis, fulfilled those types of criteria that result in a resilient system.

We need to do that. Whether like I said that gets into an LOLE because I certainly understand the point Tom is making is an excellent question but it needs to get in there somehow.

MR. COOK: Can I jump in here just for a second. So I thought I heard this morning that Tom said that there was some degree of correlated outages that was reflected in LOLE. But now Stu, it sounds like it's not -- sorry I'm just a little -- is there anything to do with correlated outages that's currently reflected in LOLE?

MR. BRESLER: Yeah you really ought to recall Tom Falin to the stand. But my understanding is that we are tweaking our assumptions in that regard to get a better picture in the winter. So if it's not in the LOLE now, the intent is to put it in the LOLE in the future.

MR. COOK: Okay thanks.

MR. RUTIGLIANO: Okay thanks again, Tom from AEMA. Just to respond to the two points. I absolutely agree with Stu that it needs to be in the planning process somewhere. I'm merely saying the way we approach this should not be used as justification for eliminating seasonal resources and should be consistent with the no-excuses risk is on the supplier approach throughout CP.

To the other question about, you know, do generators know three years ahead of time if they're taking an outage? We are to speak up planned outages to be clear not forced outages right the margin is there for forced outages.

There is long-standing I think back to the beginning practice that generators can't take planned outage in the summer, so there's certainly some precedent that you know that you can meet these capacity requirements to be there during certain months. I imagine nuclear fuel for instance I think is planned well in advance. I don't know what others would be.

And then also for better or worse I think it's a reasonable liquid market and as the delivery approaches or even within the delivery if generators know that they're going to be required to take an outage during a peak season, there's multiple pathways that they can secure replacement capacity to cover them when they're out of the market.

So yeah, I don't think -- we're not requiring that three year crystal ball for generators but there's precedent that there is a requirement to plan three years ahead and multiple opportunities to adjust as circumstances unfold.

DR. SHANKER: I think I agree with sort of half of that. To the extent that someone concurs an outage because they didn't winterize a unit and it goes into their 84D I don't think there's any debate. I agree completely with that.

I don't know if the GAD's data is refined enough to pick that up but it should be. That's a reasonable request and it's -- it's -- it presents a problem like Stu said, there's a product partitioning or characterization that's out.

I think maintenance is different because if you're -- you wanted the OF maintenance, if you want a product that has all the other features, it comes with the maintenance. If you want to have I think the Market Monitor will probably speak up.

If you want to have anybody that wants -- that's denied some of the maintenance because it's effectively planned maintence is essentially banned -- I shouldn't say banned, it's avoided, then you're saying that you're also willing to have seasonal annual -- people who would otherwise been annually restricted and then start to bid seasonal.

And I think you're on a path there that is once again going to lead you to a bunch of behavior you're not going to really want to see, you're going to have withholding issues -- the mitigation effects of well you know, I don't know if I'm going to run between 6 or 8,000 hours and that will occur between now and three years ahead.

And so I don't want to bid in the winter season -- it's a combined cycle. 24,000 hours over that period of time including starts and someone says it's reasonable for me to assume that that will be my maintenance experience that I could offer the product in that period.

And so one of the building blocks of the market must offer and blanket taking it away for or excusing or allowing planned outages would really be anathema to that. The things that are reasonable in control -- and I think those are you know some should have dual fuel and they don't or somebody can winterize and they don't -- those all fall into the bracket where I think you're talking about shifting class in a reasonable fashion.

Other -- the maintenance one bothers me because I can just -- it's inherent in the product.

MR. MONICK: Well thank you again for everyone for coming. We very much appreciate your expertise. I'd like to take a quick up-change and thank my colleagues as well especially John Neil who I realized did a lot of the leg work for putting this together.

As we mentioned earlier we expect to issue a follow-up notice in the near future with some additional questions for post-Technical Conference comments so be on the lookout for that. Thanks again everyone and travel safely.

(Whereupon the meeting was adjourned at 4:13 p.m.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding:

PJM Seasonal Capacity - Technical Conference

Docket No.: EL17-32-000; EL17-36-000

Place: Washington, DC

Date: Tuesday, April 24, 2018

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 transcription of the proceedings.

Gaynell Catherine

Official Reporter