1 FEDERAL ENERGY REGULATORY COMMISSION

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4 TECHNICAL CONFERENCE ON

5 REACTIVE POWER RESOURCES

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9 April 17, 2012

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12 9:00 a.m.

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15 The above-entitled meeting was held,

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17 pursuant to notice, at 9:00 a.m.

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1 P R O C E E D I N G S

2 (9:00 a.m.)

3 MS. CAIN: Good morning. Could our speakers

4 please take their seats?

5 (Pause.)

6 MS. CAIN: Good morning. Thank you for joining

7 us today to share your experiences with the generator

8 interconnection process and reactive power requirements.

9 There are a lot of different analogies to describe reactive

10 power to non-engineers, including the foamy head on a beer,

11 the bouncing that comes along with walking on a trampoline,

12 and a really complicated of peddling a multiple person

13 bicycle.

14 Today, we want to get past those analogies, and

15 we want to have truly technical, technical conference. We

16 are happy to have such depth of expertise on our panels and

17 among our staff, and I'm looking forward to see detailed

18 technical discussion.

19 Over the years, the types of generation on our

20 transmission system are changing. These impacts how

21 transmission providers plan for and use reactive power.

22 Today, we want to discuss reactive power resources, in

23 particular to gain a better understanding of studies of

24 reactive power needs, and to understand the characteristics

25 and the challenges of new technologies, including wind and

1 solar generation, advanced transmission technologies and
2 energy storage resources.
3 This morning, we will discuss the studies
4 transmission providers use to determine reactive power
5 needs, in particular the studies for generator
6 interconnection. This afternoon, we will discus the
7 different resources that can provide reactive power, their
8 technical characteristics, their capabilities, costs and
9 availability.
10 We will begin with five to ten minute
11 presentations from each of our panelists. After the
12 presentations, we will have questions from staff and perhaps
13 from Commissioners. From those of you watching the live
14 webcast, some of our speakers submitted materials in
15 advance, and those are available on the Commission's website
16 this morning.
17 We plan to break for lunch around 12:15, and will
18 incorporate a ten minute break in each panel, one in the
19 morning and one in the afternoon. Now I'd like to welcome
20 Commissioner Norris this morning. Do you have any remarks,
21 Commissioner?
22 COMMISSIONER NORRIS: Thanks, Mary. Am I on
23 here? Thanks. Just that I'm anxious to hear what you have
24 to say. I understand you to say, as Mary said, a technical
25 conference. This means all of you talking to engineers. So

1 don't, just don't pay any attention to me up here, because
2 I'll probably get lost. They'll explain what it all means
3 later.
4 But here's my main interest in this issue, is we
5 are changing so many elements to our system today, with
6 different kind of generation resources, different demand
7 side management possibilities, and with all the changes in
8 the physical operation, we have to think about our
9 operational changes to mesh up with those.
10 This, I think, pairs with what I've been talking
11 about recently, a system that has always been designed and
12 run and thought of from left to right, and now we have to
13 think of it as going from left to right and right to left,
14 and how do we encompass those operating, the physical
15 changes to our system with different operational changes,
16 that make this all mesh together, and create efficiencies
17 and manage accountability for the different operational
18 challenges that different resources bring to the table?
19 So that's what I'm hoping to learn from listening
20 to all you experts today, and so go for it, and I may ask
21 some questions, some non-engineer questions here. But I
22 really want you all to exchange some really technical
23 information to help us come to the right conclusions about
24 how we change or alter regulations that mesh up the
25 operational changes and needs of today's system, not

1 yesterday's system.
2 MS. CAIN: Thank you, Commissioner. Now to
3 introduce the staff at the table. To my right, we have Dick
4 O'Neill, Sassan Jalali and Jason Feuerstein. To my left,
5 Aaron Bloom, Christopher Kempley, Pat Dalton, Abdur Masoon
6 and Brian Bak, and I'm Mary Cain.
7 Our staff are from a variety of Commission
8 offices, and we have engineers, economists, lawyers and
9 policy analysts here at the table, and we're ready. With
10 that, we're ready to begin our first panel.
11 I'd like to remind the panelists that the
12 microphone in front of you, please turn it on when you're
13 speaking and off when you're not. And also please turn your
14 cell phones off when the microphone's on, as they kind of
15 interfere with the mic.
16 The panelists we are happy to have with us here
17 today, we have Noman Williams from Sunflower Electric; Yi
18 Zhang from California ISO; Eric Laverty from the Midwest
19 ISO; Dmitry Kosterev from Bonneville Power Administration;
20 Robert Jenkins from First Solar; Kris Zadlo from Invenergy;
21 Richard Kowalski from ISO New England; and Jeff Billo from
22 ERCOT. Welcome, and thank you all for coming.
23 Now I'd like to invite our first panelists, Noman
24 Williams, to give his presentation, and I believe Noman has
25 some power plant slides to go along with it.

1 MR. WILLIAMS: Yes, I do. thank you for inviting
2 us to come and to speak on reactive power issues. I come
3 from the perspective of a coop, and western Kansas is really
4 battling or dealing with lots of wind integration and
5 penetration within the system.
6 So my perspective is more from, I would almost
7 say, a customer's perspective. Not necessarily a customer,
8 but someone that's dealing with wind development and the
9 issues around that development within our transmission
10 system.
11 If we go to the second slide, give you kind of a
12 background of who Sunflower and Mid-Kansas are. We are
13 GNTs, serve effectively the western two-thirds of the state
14 of Kansas from a generation transmission perspective. We're
15 also members of the Southwest Power Pool, and so our
16 facilities are underneath the SPP RTO and the regional
17 tariff owned by six different distribution cooperatives, and
18 we operate and maintain all of our own facilities, about
19 2,200 miles of transmission, and about 1,200 megawatts of
20 what I would say conventional generation, coal and gas-
21 fired, steam and some gas turbines, and serving most of
22 those customers in western Kansas, either through our
23 members at retail or through wholesale arrangements with
24 municipals and other cooperatives within the region.
25 But we really kind of represent what I would say

1 a lot of the areas that are served, serve the western half
2 of the Eastern Interconnect, and even the eastern half of
3 the Western Interconnect, rural systems where a lot of the
4 wind's going to be developed.
5 So if you go to the next slide, we can kind of
6 see the wind map and the outline there shows SPP. The dark
7 line is the SPP region, and kind of in the middle of that
8 map is Kansas, and on the western half of Kansas is where
9 Sunflower's service area, Sunflower Mid-Kansas service area
10 is.
11 So it's in a very high value wind area, and so
12 there's a fair amount of wind development in that area.
13 Next slide. A little bit better idea of where
14 Sunflower sits within the SPP, and Sunflower is an operating
15 balancing authority within the NERC and also within the SPP,
16 and it's the kind of, I'd say, salmon-colored area there in
17 Kansas.
18 Next slide, please. Again, SPP is the heart of
19 wind country. A fair amount of developable areas there.
20 Currently in SPP, there's about 10,500 megawatts of wind
21 under active study. About 15,000 megawatts has signed
22 interconnection agreements, and of that, in the Sunflower
23 Mid-Kansas area, there's about 2,800 megawatts of wind under
24 study, 2,600 megawatts of signed IAs that aren't active
25 within the Sunflower area, and then we also have

1 approximately, well by the end of this year about 2,000
2 megawatts of connected wind on the ConnectStar Transmission
3 System.
4 Next slide please. This just a slide showing
5 what the goals are within the SPP region, and I won't spend
6 a lot of time on that. But almost every state within SPP
7 there has a goal or an RPS-type standard to meet. So
8 driving some of the development of wind and within the SPP
9 and within the, what I'd say in the Sunflower region also,
10 because a lot of the wind that's developed at Sunflower is
11 used by others within the SPP.
12 Next slide, please. This is just a map that kind
13 of shows sizes of interconnections within the SPP region,
14 and the portion kind of in the middle, that's kind of hard
15 to see, I guess, if you don't have it right in front of you.
16 But there's a green and blue and pink dots. Those are
17 relative size of connections or interconnections in those
18 areas. There's a fair amount of concentration kind of in
19 the southwest corner of Kansas, which is in our Spearville-
20 Dodge City area, which has a large concentration of wind
21 development in that area.
22 So the challenge we face -- next slide please, is
23 if you look at the size of the Sunflower Mid-Kansas system,
24 we're about 11,500 megawatt peaking system. But focus on
25 the minimum. Our minimum loads run in the 460-470 range,

1 and looking at our resources, about 83 percent of our
2 capacity is coal-based.
3 From an energy perspective, 11 percent of our
4 capacity is gas and oil-based. We have no oil, and then we
5 have about 40 percent of our energy comes off of wind, from
6 a capacity factor perspective. So looking at our overall
7 size of the facilities we have on our system, our coal
8 accounts for about 113 percent of our minimum, which means
9 we're ramping coal in minimum periods.
10 Our gas is about 130 percent of our minimum load,
11 and our wind accounts for about 26, 27 percent of our
12 minimum load. So the issue you really have is how to
13 balance that minimum, and that's just for the wind that we
14 have underneath contracts or PPAs. That doesn't account for
15 the wind that is actually connected to our system, which
16 accounts for another, by the end of 2012 will account for
17 about another 1,800 megawatts.
18 And so the real issue becomes for us is how to
19 balance the needs of the system against the needs of
20 bringing that renewal resource to market, and one of the
21 issues that really is of concern to us is voltage control.
22 So that would be where we get into the reactive
23 requirements.
24 As we begin to back that generation off in real
25 time, we lose the ability to provide voltage control, and

1 also what I would say damping control within the system, as
2 conventional generation gets on minimums, and we're
3 generating a significant amount of energy off of the renewal
4 wind.
5 So we end up with situations where we have high
6 voltage issues, which have not been a problem in the past,
7 but are now becoming a problem for us to control, and how do
8 you control those issues at the lower voltage levels?
9 Putting the reactive device is not capacity reacting, but
10 inductive reactive devices on lower voltage systems tends to
11 create operational problems, because of the size of the
12 blocks that need to be switched and to be able to control
13 voltage. So that's an area that we're struggling with right
14 now, is how to control high voltage.
15 One of the things we've discovered working with
16 SPP through the interconnection process, really the
17 interconnection process studies focus on max gen events. So
18 what's the maximum generation? What are the impacts of the
19 system to interconnect max generation off of any generator,
20 whether that be the conventional or wind, rather than
21 stepping back and looking at light load conditions.
22 You know, what are the requirements around light
23 load conditions, which is especially when wind is either
24 peaking or worse case from a reactive perspective, light
25 load and the wind is off also, because we're ending up right

1 now building a significant amount of transmission within the
2 western SPP, to move renewal resources into the market or
3 into the eastern markets, that is only being built to move
4 this renewal, really to move renewable resources.
5 At light load periods, you've got significant EHB
6 that will be unloaded, that will create high voltage
7 problems. So those are the, what I would say, voltage
8 regulation issues that we're beginning to witness within our
9 system, and then looking at ways to manage that and control
10 that.
11 I think we really need to step back and look at
12 how we're studying the system, to make sure that we capture
13 all those impacts from a peak load to a light load, begin to
14 look at the impacts of decommitting conventional generation,
15 because you've got a significant amount of renewable
16 resources on the system, and what are the impacts from a
17 damping perspective.
18 System stability becomes an issue at light load
19 when you don't have a lot of resources, conventional
20 resources on the system to damp, and you have wind events,
21 or you have outages, or are we going to begin to see some
22 reliability issues escalated because of the lack of damping.
23 You know, the one thing that I think we all need
24 to remember is most wind resources can replace megawatt for
25 megawatt conventional resources. But they can't necessarily

1 replace megavar from megavar conventional resources, and
2 they really don't provide inertial mass or damping to the
3 system on a consistent basis.
4 So there has to be a balance, and I think that's
5 the step we need to move toward within our interconnection
6 studies, is begin to look at the system on a holistic basis,
7 looking at the balance and the impacts of the overall use of
8 new technology.
9 You know, as I talk through this, I do want to
10 state that we are very supportive of wind, and as we've
11 shown by our purchases and working with the wind industry to
12 interconnect.
13 But we want to make sure that as we move to new
14 technologies, that the folks that have paid for the system
15 to deliver energy to their load in the rural systems aren't
16 also tasked with issues of paying for reactive requirements
17 for the movement of energy out of their areas into other
18 markets, or to meet national policy goals on a renewable
19 basis.
20 We want to make sure that they're not the ones
21 that are burdened with reactive, new reactive requirements.
22 I guess I'll leave you with one thing from my perspective,
23 is bars are local. Bars have to be applied where the
24 problem's at. They can't be applied remotely and move to
25 the problem.

1 So when you have a reactive problem, whether that
2 be from high voltage to low voltage and you have to provide
3 reactive resources, those have to be applied locally, where
4 the issue's at, and not in a remote place and moved to where
5 the problem is.
6 So looking at a problem in Kansas City, Kansas,
7 you can't solve that problem by putting reactive resources
8 in western Kansas. At that, I'll just let things lead to
9 questions and answers later, but you know, our goal is to
10 move to a period of where we look holistically at the system
11 for the overall interaction between renewable resources,
12 conventional resources, and look for ways to apply the
13 reactive requirements of the system broadly across the
14 system, and not just locally applied. Thank you.
15 MS. CAIN: Thank you, Noman. Now Yi Zhang.
16 MR. ZHANG: Good morning. My name is Yi Zhang,
17 senior regional transmission engineer at the California ISO.
18 In this capacity, I participate into various transmission
19 planning efforts, including reliability assessment, resource
20 adequacy, energy interconnection, cross-driven transmission
21 planning and the economic assessment.
22 In 2009, the ISO requested authority to apply a
23 uniform reactor power requirement to all large wind and
24 solar PV energy interconnection. The ISO request this
25 authority because of the large quantity of wind and solar PV

1 in our queue will displace output from conventional
2 generation, which can provide reactive power across the
3 grid.
4 Commission rejected this request, but scheduled
5 today's meeting to examine, to be a part of the attempt to
6 examine the evidence, if there's evidence exists, to support
7 to apply this request broadly to not only wind generator,
8 but also some PV.
9 The ISO's interconnection queue continues to
10 reflect the large amount of wind and solar PV
11 interconnection request. In our most recently cluster,
12 that's Cluster 5, we received over 17,000 megawatt
13 additional generation request, lots of which is wind and
14 solar PV.
15 In my cements today, I will summarize some recent
16 experiences of the study results from Cal ISO's
17 interconnection study. I also will identify the drawbacks
18 of using case-by-case approach to identify reactive power
19 need. Also, I will identify the benefits of applying
20 uniform reactive power requirement.
21 Next, I will briefly describe some examples.
22 First, in California ISO's Phase 2 study, there are a total
23 of 92 synchronous generation projects, about 5,000 megawatts
24 of capacity. Seventy nine out of these ninety two projects
25 were identified that need to provide reactive power

capacity, including .9m factor. Only certain projects were not required to do so.

We looked at those certain projects and we found most of them are in one area. It's in provider area. It's about 100 miles away on the east of San Diego. We look at the study results for different clusters in this area. In Cluster 1 and 2 in the earlier queue, we didn't require reactive power capability for the product in this area.

But in the recently-finished Cluster 3 study, we found all products in Class 3 in this area would need to provide reactive power capability. Although those products in Class 3 are either the same bus or one bus away from earlier queue project in this area.

The next example, we look at the Riverside East on the pump stream area. So that's one of the largest renewable resource areas in California. It's on the desert between California and Arizona. When we look at their interconnection request from developers, we found most of the synchronous projects in this area. Based on the technical data provided by developers, they can provide reactive power factor .95 or even wider range, using varying water (sic)
only.

Now that means from the developer's perspective, they're not a big technical hurdle to provide reactive power

as a part to this system, using varying equipment. The study for this area also show all projects in this area need to provide reactive power calibrated to the grid.

There are some other voltage-related issues we also observed from our studies. For example, the high voltage issue caused by solar PV interconnection in the distribution or service transmission system. And also, we observed damped oscillation associated with the solar PV interconnection, if some control model is being used.

We also observed a trend in overvoltage problem in high voltage grid interconnection. It shows that although solar PV in water may have dynamic mark-up capability. It may not be enough, but we still need faster dynamic response or additional dynamic devices to maintain the system reliability.

From those examples, in summary, we can get some consideration here. First, most of projects, new projects would be required to provide reactive power capability.

Second, based on the case-by-case approach, we found that later queue project at the same area, for the late queue project we asked them to provide the reactive power capability, although earlier queue project may not be required to do so.

Third, the currency (sic) in water technology allows to use area water to provide reactive power

capability.

Fourth, there are some other reactive power issues, multiple issues could be more challenging for most developers and manufacturers, and the system operators and planners. Those issues would need to be paid more attention, in order to maintain system reliability for new or renewable energy.

So there are some drawbacks of case-by-case approach. First, the current approach cannot work in our operational scenarios because of the intermittency of renewable. The studies are not efficient and very time-consuming and there are also potential of introducing unknown investment risks and unfair treatments between existing and new projects, and also unfair treatment between different clusters in the queue, when the queue grows or shrinks.

The benefit of applying a uniform reactive power requirement, including it can provide cost uncertainty for investors, and also it's a more efficient study approach and can accelerate the process and reduce the time for restudy, and ensure distribution of reactive power controls throughout the system.

And I would like to summarize the scope of the uniform reactive power requirements that we are seeking. First, synchronous facilities shall be able to achieve .95

1 leading and lagging power factor at the point of
2 interconnection, and they shall be able to regulate the
3 voltage to the point of interconnection continuously.
4 Asynchronous generating facilities' reactive
5 power capability shall be controlled by automatic setting,
6 having both voltage regulation and the net power factor
7 regulation. Also, asynchronous generating facility shall be
8 able to provide sufficient dynamic voltage support if the
9 interconnection study shows this to be required for system
10 safety of the grid. I will stop this morning, so thank you.
11 MS. CAIN: Thank you, Yi. Now, Eric Laverty.
12 MR. LAVERTY: Thank you for the opportunity to
13 come here and discuss results of how we've implemented Order
14 661-A over the last several years. The perspective I'm
15 bringing is just that. We are, my area at MISO is
16 processing the interconnection queue, among other duties,
17 and we just want to do it efficiently. We want things
18 understood between the customers, the transmission owners
19 and us.
20 MISO has no qualms with the intent behind the
21 order. Any time we've had Order 661 or 661-A mentioned in a
22 docket before you, the issue has not been the why but in the
23 how. It's all been about how do we implement this, and how
24 do we get the information from the customer to the customer,
25 and properly process the request.

1 We have found problems trying to implement the
2 letter of the order. The intent is clear. It's
3 implementing the letter that we have issues with. What I'd
4 like to do this morning is discuss the methods we've used,
5 challenges of those methods, and offer two possible
6 solutions to the issue.
7 In our quest to follow both the letter and the
8 spirit of the order, we find ourselves, the transmission
9 owners and the interconnection customers in a bit of a
10 chicken and egg situation. The customer doesn't have to
11 provide its detailed design at the request date. They can
12 provide it later.
13 We can't determine whether the system needs
14 additional reactive capability without that design, and
15 while it doesn't happen often in practice, in our -- or it
16 will with our latest reform, we could be in a situation
17 where that six month lag could encompass the impact study.
18 We might get to the point where under 661-A, they
19 have to provide the reactive data and the system impact
20 study's done and then we can't change the result there. We
21 have run into that issue, not being able to change that
22 result. So that's our chicken and egg issue.
23 What we do is currently we'll model what the
24 customer says they can do with respect to reactive
25 capability, with the best data they have into us at the

1 time. Run our studies and see if more or less reactive
2 capability is needed to maintain reliability. If there's a
3 change in generator technology, you've got to start over.
4 If they provide more detail at a later date,
5 that's typically going to require us to start over. We run
6 into inefficiencies there. With the sheer quantity of
7 renewable energy over the last ten years, we can do better.
8 There's a body of knowledge available to the industry that
9 doesn't leave us any excuse for doing better now.
10 We've seen issues literally on both sides of the
11 power triangle. Talk about low voltage under full wind
12 output, that could be an issue. I was here at roughly the
13 same spot in the table in the fall of 2004, and we discussed
14 in a panel then about that low voltage issue.
15 Now the generator technology has advanced. We're
16 not seeing this as much. When we get the full data, when we
17 get the turbine selection, that's been okay. It's when we
18 don't have the full data, that could be an issue, or you get
19 some -- occasionally we'll see a retrofitted or a rebuilt
20 turbine that had been retired in one place, rewound and go
21 into use in maybe an older model. That's a mahob (sic) up
22 there.
23 What has surprised us, although in hindsight
24 probably shouldn't have, was the high voltage situations
25 under no load conditions. The collector system for a wind

1 farm looks like a really big capacitor under no-load. So
2 fortunately, our transmission owners and our interconnection
3 customers have been able to work out those issues when they
4 have arisen in a cordial fashion.
5 We would like to address that going forward and
6 be able to take care of that up front and not be surprised
7 later. To resolve these, we seek technical options. First
8 would just be a simple stringent standard for any generator
9 connecting to the system, to be able to provide a range of
10 reactive capabilities.
11 Any additional reactive needs over and above that
12 standard would become the responsibility of the reliability
13 planning process. You know, what comes over the
14 interconnection; anything else is handled with a reliability
15 plan.
16 The advantages of this approach lie in the
17 setting of the expectations for all parties.
18 Interconnection customers would have the design parameters
19 to work with at the start of the process. Transmission
20 providers and owners when they're looking out into the
21 future and you don't know exactly what generation is coming,
22 you would know what to model, know what else is needed on
23 the system. Just that full understanding and reduction of
24 the uncertainty will help there.
25 Back in 2004, we fleshed out a number of

1 disadvantages for that idea. We could block out certain
2 technologies, specifically newer technologies as they
3 emerge, or require a mixing and matching of technologies.
4 We might have a generator with a super-conducting magnet.
5 Bags of ice.
6 The alternative proposal we came up with, if the
7 desire is to still allow the flexibility and stay away from
8 a stringent standard, would be to flop the question.
9 Instead of asking generator, what can you do, do we need
10 more, look at it from a system perspective. Say at this
11 point of interconnection, the reactive power range needs to
12 be between a minimum and a maximum point. You can look at
13 that at a few different outflow levels, no-load, full load
14 and CAF, for peak and off-peak conditions.
15 Say your design parameters will now be between
16 these two points. That would still allow the flexibility,
17 but it would put that detailed design in those discussions
18 at the proper point in a project construction.
19 We've got this fleshed out. We have discussed
20 this with some of our transmission owners, and the answer so
21 far has been that's interesting, but does it meet the letter
22 of Order 661-A? And we couldn't come to agreement on that,
23 so we haven't done that yet. But that is something we think
24 is on the table.
25 So in conclusion, MISO is looking for this

1 proceeding to provide a better path to achieve the intent of
2 Order 661-A in an efficient manner. We need to get out of
3 this chicken and egg game, and we've laid out two proposals
4 to improve the mechanics5
5 Now I would note that we've written them in
6 pencil, so to speak. We think this is a starting point and
7 ultimately, we believe the process can be improved. Thank
8 you.
9 MS. CAIN: Thank you, Eric. Next we have Dmitry
10 Kosterev.
11 MR. KOSTEREV: Good morning. Thank you for the
12 opportunity to present and share the BPA experience with
13 wind generation integration in our area. So for those who
14 don't know BPA, it's a large transmission operator, owner
15 and balancing authority in the Pacific Northwest. We are
16 the operator on the grid and to 30 community systems in four
17 states of Washington, Oregon, parts of Idaho and Montana.
18 So as of today, BPA has more than 3,400 megawatts
19 of wind generation capacity interconnected to the grid. Our
20 pre-generation exceeded 4,000 megawatts on several occasions
21 last month, and we had a really exponential growth of the
22 wind generation in the last six years, from roughly four or
23 five hundred megawatts in 2006 to where we are today.
24 It provided a lot of opportunities to learn and
25 presented many technical challenges, which we can talk about

1 today. So in the early stages of the development, you know,
2 the projects were small. When the FERC Order 661 was
3 passed, most of the projects were 25, you know, 50 megawatt
4 and they were connecting in the lower voltage system of 69
5 and a 115 kV.
6 So at that time, we or BPA does interconnection
7 studies, compliance with the NERC reliability standards, and
8 based on our studies at that time, we didn't see the need
9 for voltage control for most of the projects. So for those
10 projects, we asked them to operate in the unity power
11 factor, and use shunt capacitors as a means of compensating
12 for the reactive losses in the plant.
13 So the majority of technologies at the time were
14 induction generators, and we'll talk about this in the
15 afternoon session, and those technologies are not capable of
16 providing reactive, dynamic reactive support to the system.
17 So in order for the plant to be able to be voltage-
18 controlled, we have to install the plant reactive
19 compensation devices such as STATCOM. And again, at that
20 time, we didn't see the need for doing that.
21 So we had many stability challenges with those
22 plants, both high voltages and low voltages, as previous
23 panelists mentioned. So the specifically, you know, we had
24 several events, you know, when we had large voltage
25 fluctuations like slow oscillations on the system, and some

1 of those problems were solved later on by adding the STATCOM
2 equipment to these facilities.
3 The reasons for this were the operational
4 challenges. In some cases, the capacity control failures or
5 these things are not other sizes, as the previous speaker
6 mentioned, that the collector system losses were
7 underestimated by the developer.
8 But what really concerned me, that many of these
9 problems, we were unable to predict them in our studies
10 ahead of time, to a large extent, because model development
11 of the wind power plants significantly lagged the
12 installation of the actual facilities. So in many cases
13 model tuning after the fact was needed to capture the
14 phenomena, what happened. But in many cases, we still have
15 been able to produce the exact detail of what occurred
16 during those events.
17 So that improved the power flow modeling
18 guidelines in 2007, thanks to Enerel's great work with BPA,
19 one of the first companies which actually implemented those
20 guidelines in their system, which helped us better plan for
21 the reactive needs related to the wind generation
22 integration.
23 Dynamic models are still in progress. We still
24 are developing dynamic models, and it's kind of really be
25 concern that we have that much generation, 4,000 megawatt

online, and we're still in the process of developing dynamic models and still in the process of validating those models.

Current efforts. We're supporting the efforts with Enerel again, and the Department of Energy, as well as Utility Wind Integration Generation Group, to develop those models and to validate in our system. One of the efforts that BPA has been pursuing is putting phase-in measurement units at the point of interconnection of the wind power plant, which provides a great opportunity to hear the disturbance recordings as such occur very frequently in the west, and use those disturbance recordings for power plant model validation, as well as to performance monitor.

So we're now moving forward, you know. In 2007, we looked at the queue and we have thousands of megawatts of new generation in the queue, and now the game changed for us, you know. The generation was connecting to 500 kV system and to 30 kV substations at high voltage levels.

Typically in BPA system, the wind is very highly concentrated. If you go to Portland and you're driving east along the Columbia River gorge, you'll see a lot of wind parks, and that's where they are. Many of the projects are going to the large hubs. We call them 500 degree hubs, which can have as much as 1,200 megawatts of generation connected at a single point, and in some case we have 600 megawatts connected to 30 kV stations.

1 So now it's really a game-changer, and we needed
2 to look at the wind generation from what we call the
3 macrostability issues. So how it affects the stability of
4 the interties, and very specifically, this lower Columbia
5 area is providing very critical reactive support for the
6 interties that we operate. The California-Oregon intertie,
7 which is rated at 4,800 megawatts; Pacific Issue Interty
8 goes from the northwest to Los Angeles, rated at 3,100
9 megawatts; and the Portland Metro area.
10 So in '96 when we had outages, we determined that
11 the reliability of the nanic (sic) reactive resource in the
12 areas was really critical, was one of the major factors.
13 Lack of those resource was one of the major factors for why
14 those outages occurred. So with that amount of wind
15 generation coming in the area, we had to do large-scale
16 system studies to understand what the implications are from
17 the long-term planning perspective.
18 And we found is should we continue connecting the
19 induction generators with no voltage control, we'd
20 experience massive problems, including voltage instability
21 and fluctuations in voltage instability, oscillation damping
22 issues that previous speakers mentioned. So we decided that
23 it will be very important to introduce a requirement to
24 require wind power plants to control the voltage and operate
25 in the voltage control mode.

1 So that decision was helped by the introduction
2 of the Type 3 and 4 generators, evolution in the technology.
3 A majority of the projects right now in BP are Type 3 and 4,
4 about 60 percent, and pretty much all new projects proposed,
5 also Type 3 and 4. And that's been a pretty big enabler of
6 the wind power plants operating voltage control.
7 So in asking about voltage control, you're
8 asking, going back to the controls 201, you're asking three
9 questions. How much you provide, how fast you deploy, and
10 what you gain of your controller. So in the BPA, we're
11 asking for .9 dynamic power factor at the collector station,
12 and in addition to this, we're asking for the static shunt
13 capacitors to compensate for the reactive losses in the step
14 up transformer and collector system.
15 In some cases, we find that it's more economical
16 to put the shunt capacitors at the BPA substation, and we've
17 done this on many occasions. So how fast, we don't
18 prescribe how fast, but we're trying to take best advantage
19 of the available technologies. We understand there's a
20 difference if you have a distributed reactive resources,
21 versus concentrated reactive resources as in STATCOM.
22 You'll have different response time, and we allow for those
23 differences to occur.
24 And the deployment rate, which were found in many
25 cases, it is very important to have a droop characteristic,

so we can control the high side voltage. Now in the conventional, pass controls high side voltage. So controlling for the droop was very important, to enable the stable reactive sharing among the multiple plants in the hub. Particularly we have hubs with 6, maybe sometimes 12 plants. So we need to make sure that they all behave together.

Again, having uniform requirements is important to, for reactive power sharing. If you have multiple projects at the same location, that's very important, to make sure that they don't fight each other, and they uniformly provide the fair reactive support to the system.

Finally, I think, you know, it's important for the wind developers to understand that it's in their benefit to control the voltage. I talked John Unger last night, and he said like back in the 1920's, when the AVR was introduced for conventional power plants, the power plant owners wanted to have AVR, and not necessarily for stability reasons, but for their own reasons to control their voltage, so they don't experience high over-voltage safety problems when we have load rejection issues.

So I think, wind generators are in the same position. You want to have AV so you protect your equipment from unexpected voltage fluctuations from the outages, from the voltage rises that occur on the system. We had event

1 recently which confirmed that. We had a project which
2 normally operates in the voltage control mode, and then for
3 whatever reason it was switched to the power factor mode and
4 that coincided with the breaker outage, and we had a pretty
5 significant voltage run-up. In a matter of several minutes,
6 voltage went from 245 to 260 kV on a 230 kV system. And we
7 obviously want to prevent this by having the good voltage
8 control. Thank you.
9 MS. CAIN: Thank you, Dmitry. Now we'll switch
10 and have a generator's viewpoint, Robert Jenkins from First
11 Solar.
12 MR. JENKINS: Thank you. Thank you for
13 inviting me this morning. I mean I knew John Unger was old;
14 I didn't realize he was around in the 20's, but okay. I'd
15 like to thank you for the opportunity to participate in the
16 panels today. My name is Robert Jenkins, I'm the Director
17 of Utility Interconnection at First Solar. Listening to the
18 pervious panelists, it pulled a little on my heart strings.
19 I was a transmission planner for 20 years at PG&E, planning
20 the 502 30 kV systems and responsible for regional
21 coordination.
22 The last ten years, I've been working on
23 connecting various types of power plants to this grid, at
24 one time conventional plants. Now I'm working with
25 renewable plants, and then with for solar, working on

1 connecting renewable plants for the past three and a half
2 years.
3 A little bit of background of First Solar. We
4 are not only a module manufacturer; we're also a project
5 development company. We also do EPC. So we can do
6 everything from soup to nuts. We can develop a project. We
7 can build it. We go work with utilities for the coftic
8 (sic) agreements as well.
9 We've built projects that are currently
10 operational. They range in size from around 17 megawatts.
11 These were transmission connective projects, from around 17
12 megawatts up to about 80 megawatts. We're currently
13 building some larger projects now in California, ranging in
14 size from 230 megawatts up to 550 megawatts. So they're
15 getting bigger in size.
16 We've also moved a number of other proposed
17 projects through the interconnection queue of many different
18 utilities. It gives us a good perspective of kind of what
19 different parties are doing out there for their
20 interconnection studies. In this particular effort here to
21 look at reactive power, back in I think Cal ISO mentioned in
22 2009, the PV industry was just starting to move from the
23 rooftops to the large utility-scale projects.
24 And the requirements were quite different. When
25 we're on the rooftops, it was IEEE 1547, which generally

1 said stay away from reactive controls, be a benign element
2 on the system. That's changed, and now the manufacturers
3 are catching up with equipment than can support a more grid-
4 friendly interconnection.
5 We generally see ourselves as helping to regulate
6 system voltage, and are more than willing to provide
7 reactive power support. There is a cost to it, so it's not
8 something we just want to say in all cases it's required to
9 provide.
10 But you know, if there's a reasonable showing
11 that you need to provide, we stand ready to provide reactive
12 power support. We've seen again, a lot of studies,
13 different levels of rigor but, you know, we don't really set
14 a really high bar for that showing, because we understand
15 it's difficult when you have queues that have thousands and
16 thousands of megawatts. You don't know which will develop,
17 which of them won't. We just want to make sure that when we
18 do spend the extra money to provide reactive support, that
19 it is really being used.
20 We've had cases, for example, where we're
21 connecting PV plants close to power plants, and really the
22 PV plant really did not control voltage. It's all being
23 done by the power plants. So in those type of situations,
24 it's a bit of a waste.
25 But where we do see some issues or concerns is

1 some of the other facets to reactive power. This includes
2 response characteristics, includes things like how reactive
3 power is provided to various system voltage levels. While
4 we have yet to receive a study that says that we need to
5 provide very fast dynamic response is needed by STATCOM,
6 that hasn't prevented it from being required from time to
7 time.
8 A couple of cases that we've had where it's
9 required, it actually didn't even come up in the study. It
10 came up in a LGA negotiation, that said it had to be so fast
11 that it couldn't be provided by the solar power plant
12 itself, and we needed to install a STATCOM.
13 We were able to negotiate a hybrid version of one
14 that was a little lower cost, but nonetheless it was an
15 extra cost there, and in one case, it's one of these
16 situations where the plant's connected to a stiff part of
17 the transmission system, and it just sits at one limit all
18 day long. It really doesn't do anything.
19 But since our projects are project-financed,
20 there is a cost to these reactive controls, and it needs to
21 be considered when doing these studies. I think it's also
22 in the customer's interest as well. We're typically dealing
23 with the local utility. At least for solar power, we try to
24 site in the area of the customer. So these costs are, if
25 they are extra costs, are going to be experienced by the end

use customer there.

The other thing I would like to bring up, that cites the speed of response. The other thing I'd like to bring up is the reactive capability requirements for asynchronous generators versus conventional generators. If you can pull up Slide 5 here, okay.

What we have is we have, of course it's a little bit difficult to see, just a little schematic here of an interconnection. You can see an array there on the left, and they've collected up and they're put through a collector station and sent out a gen-tie to the utility receiving station at the interconnection point.

And you can be sharing the gen-tie. You can be sharing the gen-tie with a conventional generator. You can be sharing the gen-tie with a solar thermal plant that uses a rotating machine. And what we find is that the PV plant's requirement is measured all the way over to the utility plant. The point of interconnection in the diagram as shown as Point A.

While the synchronous generator requirement is measured at its generator terminal, can be -- I've seen different utilities define generator terminal differently. But for this case, let's just say it's Point C. Therefore, you end up with a situation where the synchronous machine knows quite well what its requirement. It's pretty easy to

1 figure out. It really doesn't vary much with system
2 conditions, and they can just order the equipment and
3 they're done.
4 But for the asynchronous generator, it requires
5 regulating at the POI. It could be remote, quite remote,
6 may or may not be done within the plant fence itself. You
7 may have go in and install additional equipment somewhere
8 along the gen-tie, closer to the POI.
9 So what we have is a disparity in the way
10 conventional generators are required to perform, versus
11 asynchronous generators. So what we'd like to do is get
12 those better aligned, figure out what is the right answer
13 and get those better aligned.
14 There's a number of other dimensions that --
15 where there's potential for better definition. I mean you
16 hear the word "dynamic." That's in the eye of the beholder.
17 Dynamic is not really defined. Is it continuous control?
18 Is there a speed of response, and different utilities view
19 the word "dynamic" differently, and so we end with varying
20 requirements.
21 There's a number of other areas as well, is how
22 much reactive power should you have to produce when the
23 system voltage is high? Normally, you don't need reactive
24 support when you have high system voltages. But some
25 utilities require you to provide reactive support over the

1 entire voltage, potential voltage range, which presents some
2 design challenges.
3 There's also some questions as when you're at
4 less than full power. We have modular systems. Some the
5 inverters can be off-line, and so maybe at reduced power.
6 Do you have to provide full reactive capability even when
7 some inverters are off-line, or is it reduced proportionally
8 as your power level goes down? Those are areas where
9 different utilities look at it differently.
10 There's a number of issues like this. They're
11 actually quite well-raised. I don't agree with everything
12 that it says, but the NERC Interconnection and Variable
13 Generation Task Force, IVGTF just issued a report last
14 month, where they go through a number of items about the
15 different facets of reactive power, much more than simply a
16 pulse of .95 at the POI, describing the different
17 characteristics and different ways the definitions could be
18 improved.
19 So in conclusion, I'd like to say PV is ready,
20 willing and able to step up and provide reactive support and
21 voltage control when needed. There is a cost to providing
22 it, so we want to make sure that when it is provided, it is
23 actually needed by the system.
24 There are existing LGIAs. I mean excuse me,
25 existing 661-A could be improved, could be improved with

1 better definitions of what's required, and also I believe
2 that everyone should take a look at the NERC IVGTF report,
3 especially on reactive controls. There's a lot of good
4 information there. Thank you.
5 MS. CAIN: Thank you, Robert. Kris Zadlo.
6 MR. ZADLO: I'd like to thank you for inviting
7 me to speak here today. Just like Robert, I started my
8 career at Commonwealth Edison. I was there for ten years
9 and when I left I was the Technical Studies Director,
10 responsible for performing voltage studies there.
11 So I can appreciate the argument on both sides.
12 The last 12 years I've been in the independent power
13 producer side of the world. For those of you who aren't
14 aware of Invenergy, we're a large utility-scale developer of
15 both natural gas and wind facilities. We've developed over
16 66,000 megawatts of large facilities, and in the United
17 States, we've developed 30 wind parks totaling 26,000
18 megawatts.
19 What's typical about our wind parks is they're
20 located in remote places, and our generator tie lines that
21 connect our collector stops to the utility's point of
22 interconnect are on average about, you know, five to ten
23 miles long. Some are longer, some are shorter.
24 But that's to the collection substation, and from
25 the collection substation we have feeders that connect all

1 the respective wind turbines, and those feeders can be as
2 long as seven miles. So on average, when you look at that
3 last turbine on a string, all the way back to the point of
4 interconnection, you're talking about 17 to 20 miles. So
5 that's kind of your typical characteristics of a wind farm.
6 What's also typical about reactive power voltage
7 support, and it's been mentioned, is voltage support is very
8 local. Unlike real power that you can push long distances,
9 reactive power has to be produced locally. So that kind of
10 your two bookends of the issue here.
11 So it's been our experience in order to maintain
12 the required power factor at the point of interconnect, and
13 to maintain our system, you know, this is a quite
14 sophisticated system, we have to purchase additional
15 reactive resources, sometimes capacitor banks, sometimes
16 generators with an expanded power factor, in order to
17 operate our own, what's called a mini-grid.
18 You know, we take maintaining the power factor at
19 the point of interconnect very seriously. It requires
20 additional resources, both physical and financial, and we
21 believe that Order 661 and 661-A kind of strikes a fair
22 balance between what should be required out of variable
23 resources.
24 On one hand it ensures that the increased
25 reliance on variable resources do not degrade reliability,

which is important, but on the other hand, it also goes and makes sure that variable resources don't unnecessary have to install costly equipment.

When it comes to voltage studies, I think we would have the following concerns. We would be against allowing utilities to deviate from Order 661-A. Again, we feel that it strikes the appropriate balance. The system impact study is the proper place and time for that analysis to be performed, and there should be no need for the utilities to have to require the generator to fully design their collection system. Generic data is more than sufficient in order to perform the voltage study.

This one seems to be quite obvious, but new generating resources shouldn't be required to mitigate pre-existing problems. If it's determined that additional reactive support is required, there should not be one-size or one-type-fits-all approach.

Instead, there should be a broad-based solutions analyzed, and the least cost solution should be determined, and things that should be considered is modification of voltage schedules, or different operating procedures; switching of existing equipment, and then finally the installation of static devices.

The utilities need to establish and post clear, transparent, non-discriminatory study methodology, and

1 unfortunately right now currently, we have very vague and
2 open-ended requirements that should not be accepted by the
3 Commission. I'll quote you literally. This out of
4 Utilities Interconnection Handbook on voltage requirements
5 for a new generator interconnecting to the utility, and it's
6 literally two sentences long.
7 "The voltage level of a new transmission facility
8 will be determined by the point of interconnection on the
9 system, the megawatts, the megavar capability will be
10 determined based upon joint studies." That's it. How am I,
11 as a new generator, to know what sort of voltage analysis or
12 reactive power analysis will be performed, based on that two
13 sentences in the utility's interconnection handbook?
14 Literally, that's all there is.
15 So kind of to summarize what we face is these
16 studies can be somewhat black-boxed. We don't know how they
17 will be performed, what's going to go into them and what's
18 going to come out of them. So how do we fix the problem?
19 Well, in order to come up with an acceptable methodology,
20 the first thing that needs to be established is what sort of
21 cases will be used to perform the analysis? Are we going to
22 use peak load, light load, something in between, and how
23 will those cases be developed?
24 Generation dispatch is extremely important, and
25 that methodology should be spelled out before the analysis

1 is performed, so there is no discrimination. The cases also
2 need to be realistic, depicting actual operating conditions.
3 Unrealistic cases with unrealistic dispatch scenarios should
4 not be accepted.
5 Another thing that seems to be obvious is we
6 should know what the normal operating practice is of the
7 utility as far as voltage goes. You know, what is the
8 normal and emergency voltage range for the utility?
9 Now at a minimum, the study that gets performed
10 needs to be consistent with how the utility performs its own
11 internal study, in order to determine whether it needs
12 additional reactive resources like capacitor links. The
13 study should be consistent, and that kind of concludes my
14 initial remarks. Thank you.
15 MS. CAIN: Thank you, Kris. Now we'll go back to
16 some transmission perspective from Richard Kowalski.
17 MR. KOWALSKI: Good morning. My name is Rich
18 Kowalski. I'm the Director of Transmission Strategy and
19 Services for ISO New England. I'm responsible for
20 generation interconnection, among other things. I
21 appreciate the opportunity to participate in discussions
22 today, and share our experiences in implementing Order 661.
23 We've interconnected only about close to four or
24 five hundred megawatts of operational wind, with about at
25 times close to 4,000 megawatts in our queue, and project the

1 potential of onshore and offshore, somewhere in the 12 to
2 24,000 megawatt range. So in a sense it's a little
3 frightening, because some of our experience, as I share some
4 of our experience.
5 Order 661 modified the requirements to integrate
6 wind, based on views at the time with a lot of the technical
7 limitations perceived for the wind resources. However, if
8 the objective with the generator interconnection procedures
9 is to support the interconnection and integration of wind,
10 procedures really should result in a plant that can
11 reasonably and practically operate.
12 What our experience is showing is that the
13 standards on developing reactive requirements on a case-by-
14 case basis are actually undermining the ability of the
15 plants to operate. It's important to recognize that
16 generation, with its inherent physical and electrical
17 characteristics, is really an integral part of the
18 transmission system's capability. The impact of the
19 generation extends just beyond the use, the megawatt use of
20 the transmission system, but the capabilities and those
21 characteristics affect the voltage performance and affect
22 the stability performance of the system.
23 So the less support that is provided by the
24 generation itself actually results in a diminishment of
25 system capability to support that generation that's trying

1 to interconnect, and we have witnessed that. So the
2 transmission system really needs to have inherent capability
3 and flexibility to deal with ever-changing conditions.
4 The flexibility is limited, so that the amount of
5 resources on the system cannot participate effectively to
6 support system functions, such as dynamic support -- the
7 dynamic reactive support grows. So the greater the
8 population you have of resources without these
9 characteristics, you end up in somewhat of a death spiral,
10 in terms of what it's doing to system capability and their
11 own ability to operate.
12 Again, this is particularly a problem in wind
13 generators are often connected, at least in the New England
14 system, into weak areas of the systems that don't have an
15 abundance of a reactive margin or a dynamic margin, and
16 they're eating into the capability that exists on the
17 system, and further eroding it, degrading the performance of
18 the system and of the generation itself.
19 So again, in the Order 661, looking at a case-by-
20 case basis, you know, it perhaps does not recognize and
21 underestimates the prevalence of the conditions where you
22 have multiple generators, and if you're just looking at them
23 on a case-by-case energy competitive basis, the aggregate
24 impacts of the multiple generators is not necessarily
25 readily seen until they actually are in operation.

1 So currently to implement the procedures, to
2 determine the reactive power requirements on a case-by-case
3 basis, we're using steady state instability analyses,
4 looking at limited, I'd say a relatively limited
5 representative subset of anticipated system conditions.
6 It's not possible to study all the possible
7 conditions on the system. So our study practices, and I
8 think mostly everyone's study practices, both for planning
9 and operating the system has been to look at a limited
10 subset of conditions, based on what you expect, worse case
11 conditions, taking in account the technology based on the
12 models provided by the developers and the manufacturers to
13 represent the equipment and how it will perform.
14 For wind generators, they have to demonstrate
15 through each study that the dynamic reactive capability is
16 necessary to ensure reliability and safety. While this
17 approach may seem adequate, you know, gee, I've got my set
18 of conditions, I do my study and poof, I determine what the
19 requirements are.
20 I thought about this, and our whole approach to
21 doing both planning and operating studies is actually
22 somewhat based on an evolution recognizing the system has a
23 certain latent capability to it. It's just a lot of what
24 you're doing is based on past practice.
25 So a lot of the studies that were doing a limited

1 subsets of system conditions are based on an anticipation,
2 backed by historical experience, of capabilities that exist,
3 largely provided by the existing or the majority set of
4 synchronous generators.
5 This approach of limited testing, in combination
6 with the understanding and experience, has historically been
7 adequate. But as noted, if this approach is based on
8 certain expectations and latent capabilities, and around
9 generators that largely have dynamic and reactive voltage
10 control, that approach really is no longer adequate to
11 assess what the system needs really are.
12 In actual system operations, you've got to
13 consider conditions that are well beyond that which we
14 usually experience. It's not practical to cover all of
15 those possibilities. Load, varying load, high load, light
16 load, different generation cases. We do try and cover a
17 number of those. But to anticipate covering any, all the
18 possibilities is really not practical.
19 So you know, if we work to truly expand, based on
20 what we've learned and our experience with the plants we
21 have online, if really like to work to design a regimen of
22 testing, to try and capture all of the conditions, there
23 would be a multi-fold increase in the study requirements,
24 time and cost.
25 And there's no guarantee that we'd still capture

1 all of the operating conditions, consistent with the wind
2 generator's interest. Unforeseen consequences add further
3 complexity. We've found it difficult to obtain accurate,
4 well-functioning models for plants and their changing up to
5 the very last minute.
6 So what happens is we take something that's very
7 tightly designed under tight margins, with a minimalist
8 case-by-case approach. Something changes, and it may seem
9 like a relatively small change, and suddenly we've got a
10 plant that has operational problems, as we are when a
11 potentially material modification is due to subtle changes
12 because there is no margin that's built into the system.
13 Some recent experiences. The recently completed
14 wind generators with a small number of number of modest
15 changes. The small number of changes, and I think small
16 relative to what we would have anticipated as small for a
17 conventional generator. That plant has 30 to 40 percent
18 restrictions on its output, due to voltage and reactive
19 requirements.
20 With a more robust, dynamic voltage control
21 design and reactive compensation at that plant, we're to
22 expect that that would not be the case. As a matter of
23 fact, the generator has requested us to go back and modify
24 the design and do additional studies to eliminate those
25 restrictions, and it will be through reactive compensation

at the plant.

Without the resources, dynamic controls, inertial characteristics, power factor of some reactive margin, the operators have little room to address problems. Operational limits of the plants become more prolific in the absence of equipment and margin. Interconnection of the 200 megawatts of wind in one area has resulted in a decrease in area export capability for to support wind from about 1,000 megawatts and 700 megawatts, caused by the absence of the support capability of the generators.

Again, everything passed the case-by-case tests, but when you put it all together and try and operate it as a system, the aggregate effect is a diminishment. Robust dynamic voltage support at the plants would have eliminated this, and it manifests as problems increase.

Interconnection of many 5 to 100 megawatt generators in an area don't show a reliability problem if studied individually. However, the aggregate impact is that we've got one area that you can't operate more than 100 megawatts of wind. This would be substantially mitigated if each of the plants had more robust dynamic voltage control in voltage control range.

Transmission op conditions, typical operating conditions are really compounding issues with the, for the operation of plants. We've got one plant that like a less

1 than 50 megawatt wind generator cannot be online during six
2 different facility outage conditions.
3 There's a less than 100 megawatt wind generator
4 must be reduced to levels below 50 percent to 25 percent,
5 with 25 different equipment line outage conditions in an
6 area. So it's more than 200 miles of transmission lines
7 covering, I think, a two-state area. So when there's no
8 margin, but the minimum to interconnect a plant on a case-
9 by-case basis, there's no margin to anything, and it's the
10 plant that's directly impacted.
11 So these demonstrate that relying the Order 661
12 has not been, in our experience a practical or desirable way
13 to address the reactive power requirements, and it's
14 undermining the ability of the plants to actually operate.
15 So this really supports the need for a
16 standardized requirement or reactive power requirement from
17 wind generators. Clearer expectations from the start, and
18 we'll end up in fewer operating restrictions.
19 MS. CAIN: Thank you, Rich. And now our last
20 panelist, Jeff Billo from ERCOT.
21 MR. BILLO: Good morning. My name is Jeff Billo.
22 I'm manager of Transmission Planning at ERCOT. First, I
23 want to commend the Commission for taking up this very
24 important issue for the industry. As most of you are
25 probably aware, ERCOT is an island system. We have limited

1 DC tie connections with the Eastern Interconnect and with
2 the Mexico CFE system.
3 Our peak load is approximately 68,000 megawatts,
4 and we currently have nearly 10,000 megawatts of wind
5 generation interconnected on our system.
6 We've had a peak output of wind of roughly 7,900
7 megawatts. We're currently implementing a transmission plan
8 to support over 18,000 megawatts of wind generation on our
9 system, that's known as the competitive renewable energy
10 zone project or CREZ.
11 Part of ERCOT's role in the CREZ plan was to plan
12 adequate reactive power support. So at ERCOT, we have a lot
13 of experience in integrating large-scale renewable
14 generation. As several of the panelists have already
15 mentioned early, when turbine technology was not capable of
16 providing reactive support, we've seen sort of two
17 approaches evolve out of that to address that issue.
18 The 661-A approach was to look at wind generators
19 on a case-by-case basis as they interconnected on the
20 system, and determine what the reactive power needs were at
21 that time.
22 In ERCOT through the stakeholder process, we took
23 a different approach, and in 2004, we had roughly about
24 2,000 megawatts on our system, we were recognizing some of
25 the problems associated with having a lack of reactive

1 support for all of this renewable generation on our system.
2 So we implemented a standard of, a uniform
3 standard of .95 plus or minus power factor at the point of
4 interconnection. That standard was a uniform standard
5 applied to all generators on the system, wind, conventional,
6 just across the board. In 2009, we modified that standard,
7 so that all generation resources were required to provide
8 that reactive power dynamically. So plus or minus .95
9 dynamically.
10 Based on our experience with the issue, we
11 believe that the uniform approach has given us a lot of
12 operational and planning benefits through the years.
13 Operationally, if you can imagine if there's a disturbance
14 on the system, where our operators need to call on
15 additional reactive support, then they can do that without
16 having to try to figure out which plants can't provide that
17 support and which plants cannot.
18 They know that each plant has a requirement to
19 provide a relative amount of the same type of support,
20 reactive. In planning, we've also seen the benefits of
21 this, where we know that we can rely on a base level of
22 reactive capability, which mitigates the need for, to plan
23 for disproportional contributions from a multitude of
24 generation resources.
25 And given that system needs change over time, an

1 approach where each new generator is analyzed to determine
2 its reactive requirements may present planning challenges,
3 because what may have been adequate at one point in time may
4 no longer be adequate in the future.
5 An example of this is if you consider the West
6 Texas system in ERCOT. It's where we have the majority of
7 our wind generation. A number of years ago, there were a
8 number of conventional plants out there. Recently, a lot of
9 those conventional plants have retired, until today we see a
10 situation where we see a significant number of hours
11 throughout the year, where we have only wind generation on
12 the system, on our westernmost portion of our system.
13 So if we would have planned a number of years to
14 only rely on whatever planning studies would have been
15 conducted at that time, to determine what the reactive needs
16 were for each of the plants that were interconnecting onto
17 that system, then we would be deficient today, and we would
18 have to do a lot of additional reactive planning at this
19 time.
20 So based on our experience, it's ERCOT's position
21 that a uniform standard is appropriate to address system
22 reliability.
23 MS. CAIN: Thank you, Jeff, and thank you all of
24 our panelists. Commissioner Norris, did you have any
25 questions at this time? Not right now? Okay. Before we

1 get into staff questions, now might be a good time to take a
2 ten minute break. So we'll take a quick break and we'll
3 reconvene here at about 10:30.
4 (Whereupon, a short recess was taken.)
5 MS. CAIN: Would folks please return to their
6 seats and we'll get started with questions?
7 (Pause.)
8 MS. CAIN: Welcome back. We'd like to start with
9 some questions from staff, and the first question, which I
10 think I'd like -- I think it's mainly geared towards the
11 panelists who are transmission operators, but if our
12 generator panelists have anything, an opinion on it, we'd be
13 interested in hearing from you too.
14 Several of the ISOs, I know, have made efforts in
15 the past several years to cluster their queues, to help with
16 studying some of the aggregate impacts of generators.
17 I'm curious how, whether clustering has helped
18 you to see some of the aggregate impacts of generators in an
19 area, and to the extent it's not helping or there is
20 something that the clustering isn't carrying over to the
21 system impact study, to explain a little bit about what's
22 going on with that. Are there any panelists who'd volunteer
23 to speak first? Eric, thank you.
24 MR. LAVERTY: Sure, thank you. There's two
25 aspects that we're talking about here when you come to the

1 clustering study. When we talk about the reactive
2 capability of the interconnection customer, that's more of a
3 local issue. What we've seen with the clustering is the
4 aggregate may produce a dynamic issue with a reactive fix, a
5 couple of hundred miles away.
6 So you know, any one of them under study, you
7 know, maybe you don't see it, you don't see it, and then
8 somebody trips it, and then you're into a question of well,
9 you know, is this a numerical problem or is this really a
10 problem with the aggregate study, we're able to see those.
11 It hasn't really been our experience that because
12 of the timing on getting the information in for the reactive
13 capability of the individual generators that we've had to
14 local type issues on that. Again, you do have -- the
15 generic data is pretty good for a lot of purposes. It isn't
16 good enough when you're in that broader aggregate study.
17 If you're that close to the margin, you probably
18 have other issues anyway. So that's -- if that's helpful,
19 I'll stop. If not, I'll take a follow-up here.
20 MS. CAIN: That's helpful.
21 MR. O'NEILL: Can I ask? You said numerical
22 problems. What do you mean by that?
23 MR. LAVERTY: Well remember, the software you're
24 using for these studies does, numerical models. It's
25 iterative technology. You have a solution tolerance in

1 there, and this is a question that we've -- well, we dealt
2 with a while ago, and then we said you know if you might be
3 over the limit.
4 But if your generator's impact on that limit is
5 within the tolerance of your solution method, your software
6 tool, we really don't want to assign that to the generator,
7 because you know, if you solve it again, you'd be under the
8 limit.
9 MS. CAIN: Thanks. Any of our other transmission
10 panelists? Dmitry.
11 MR. KOSTEREV: I mean sure, I can offer some
12 comments here. So the specifically to BPA. So we have
13 hubs, wind generation hubs which have say 1,200 megawatt of
14 wind generation connected to the same substation.
15 Typically, it's a 500 to 30 transformer and then there's
16 several lines going to the individual projects, two 30 kV
17 lines going to the individual projects.
18 We have eight to ten projects in hub, and
19 obviously when you have configuration with this, it
20 certainly makes sense to do the cluster study, to evaluate
21 the effect of the entire hub on the global macrostability
22 issues.
23 I'm talking, I really want to draw this
24 distinction between the local voltage stability issues and
25 the macrostability issues, how the voltage control and

1 dynamic reactive resource impact the process capability of
2 major interties, and export capability out of the region.
3 We also have studies which were designed using
4 the sequential approach. One of the studies has a 600
5 megawatt of wind. It's a midline connected to 30 kV level,
6 and we had a very large number of operational challenges for
7 that, largely related to the coordination of reactive
8 resources within the site.
9 When you have a plant which is using, for
10 example, shunt capacitors as earlier plants were, and then
11 you have a plant which is a modern plant, which uses Type 4
12 or Type 3 machines which are capable of dynamic voltage
13 control, it's very difficult to coordinate them to provide
14 appropriate reactive support to the system.
15 What we've seen more often is that the plant with
16 the dynamic reactive capabilities, which are very valuable
17 for us, because normally we operate the system at high
18 voltages, and we need to carry some reactive resource for
19 contingencies, like TPL contingencies and minus 1's and
20 minus 2's.
21 In our N minus 2 severe, and many of them
22 originate actually outside our control area, and when those
23 occur, they draw a large amount of reactive from the system,
24 and we rely on the generators to provide dynamic reactive
25 support in doing this large interconnection-wide

1 disturbances.
2 So it's important to carry a proper amount of
3 dynamic resources, and dynamic resource is more important
4 for us, you know, then just, you know, switches and shunts
5 and so forth. And where I'm going with this, you know, the
6 site, you know, that we have has a combination of the plants
7 with shunts built earlier, and the new projects which have
8 the dynamic reactive controls.
9 What we see is that very often the plants with
10 dynamic reactive controls, they respond to voltages and they
11 operate at the full reactive output. So there's not nothing
12 left to respond to contingency. When the plants with the
13 shunts, you know, they have difficult time switching their
14 shunts, and you end up in a very vulnerable position, that
15 you've used all the reactive, available reactive resources
16 for the wind realm, and you have nothing left, you know, for
17 contingency.
18 So that's another reason that coordination of
19 resources within a hub is very important, and having cluster
20 study would help to expedite it --
21 MS. CAIN: How much does the system impact study
22 take account of that coordination between the reactive power
23 resources? Is that something you study at that point, or do
24 you wait until closer to the operations time frame to look
25 at that?

1 MR. KOSTEREV: Well, we would -- again, if you
2 have uniform requirement, then you apply it to all the
3 plants in the hub, and then you study them as they meet this
4 requirement.
5 If you it sequentially, you know, maybe the first
6 project doesn't need reactive. Maybe you can put the shunt
7 capacitors. Maybe the second one doesn't need it, you know.
8 But on the third one, it kind of escalates the reactive
9 requirements as you move forward, which creates imbalance
10 between the individual plants and also the fairness issue.
11 I think our customers say they want to be treated
12 fairly. So I have as much reactive as my neighbor, and the
13 sequential approach kind of defeats that.
14 MR. BILLO: In ERCOT, we're not FERC
15 jurisdictional in this regard, so that, you know, we don't
16 have a key system and we don't do that cluster analysis for
17 a typical generation interconnection. But we have performed
18 a similar analysis when we did our CREZ analysis, and during
19 that analysis, we found it very helpful to assume that all
20 of the additional generation that was going to interconnect
21 on our system would be able to meet the .95 dynamic
22 standard.
23 That allowed us to go in with a set assumption on
24 the reactive support from the generation, and any additional
25 support that we needed, we were able to plan for with

1 additional capacitors or reactors or SVCs on the
2 transmission system. So in that case, we found the uniform
3 standard to be very helpful.
4 MS. CAIN: Yes.
5 MR. KOWALSKI: At ISO New England, we don't
6 currently have a clustering system we're studying
7 sequentially. We have considered, you know, whether there
8 would be merits here. One of the things to keep in mind is
9 we do have competitive energy markets, and most of the wind
10 generators are actually interconnecting in a competitive
11 energy basis.
12 So even within the studies, while trying to deal
13 with that in a cluster basis, you might end up with solution
14 that might be a little better, you still never, in a
15 situation where you're studying all the aggregate impacts of
16 everything operating together.
17 MS. CAIN: Yes, Noman.
18 MR. WILLIAMS: Since we're really more of a
19 transmission owner and a transmission operator, SBP is our
20 R2 and does most of the studies. They are doing a cluster
21 approach. Has it really helped to define more of the
22 reactive requirements or the interactive? I don't believe
23 it really has at this point.
24 It gives a little bit of indication, but really
25 what we're seeing, at least in the cluster process, is it's

1 really more defining the transmission requirements in order
2 to get the amount of wind connector, the amount of
3 generation connected within the western half of the SBP.
4 I believe that, identification of that
5 transmission infrastructure requirement is really masking
6 some of the other issues that are there, that they're
7 really, you don't have time to get through, because there
8 tends to be a push to get the projects or the studies done,
9 get an answer so folks can move forward with their projects.
10 So a lot of the interactions between existing or
11 future generation and how the reactive requirements between
12 those is really not something that gets a lot of activity or
13 a lot of study at this point, because of the desire to get
14 projects completed.
15 MS. CAIN: Okay. So it sounds like there's a
16 trade-off between getting the study done quickly, and doing
17 the detailed study to catch a lot of these things?
18 MR. WILLIAMS: Correct.
19 MS. CAIN: Okay. Yi.
20 MR. ZHANG: In California ISO, we organize the
21 generation in kinetic study. It's a cluster approach. But
22 there's a -- I don't know if it's different or similar from
23 other ISOs. Our study basically is a two dimension. When
24 you talk about cluster, it's kind of a time dimension. You
25 have a Class 1, Class 2, Class 3, Class 5. So different

1 time window when they submit request.
2 Again, within each cluster, we study that routine
3 request, based on the geographical locations or
4 electrically, distance between each one. It makes sense to
5 us to study generation interconnection request at their
6 geographical location, because in California, it's many
7 kinds of renewable generation interconnection requests.
8 They're very location-constrained. So you're
9 located in some -- we also called it a crisis, because the
10 example I gave this morning, Riverside East, in the desert
11 between Arizona and California.
12 Those renewables serve the same transmission
13 corridors, through their identity to load center, and it
14 makes sense for us to identify, to study them together, to
15 identify the transmission needs, and also reactive power
16 needs.
17 If there's some water issue or reactive power
18 issues in those areas, those operators share the cost. If
19 we need additional reactive power support, they also share
20 the cost. So it's just basically what we were doing right
21 now.
22 MS. CAIN: Thank you. Do you have a question?
23 MR. BLOOM: Yeah. Turn my mic on. One of the
24 things that a couple of people touched on was the problem of
25 only looking at peak load conditions, when analyzing the

1 reactive power requirements, and some of the people talked
2 about well, you don't want to start looking into too many
3 requirements, because that just increases the time and money
4 needed to look at the problem.
5 So I've got two questions in that line. One is
6 are there any Commission regulations that limit you to only
7 studying these peak load scenarios, and secondly, what would
8 be an ideal mix of scenarios that you would want to look at?
9 Would you want to just look at a low load situation and a
10 peak load? Would that cover most of your problems, or would
11 you want to take a middle of the road approach?
12 MR. KOWALSKI: I guess I'll jump in. I mean we
13 don't feel that there's anything in the regulations that
14 would prohibit us from looking at a multiple range of load
15 conditions, and as time has gone on, we've discovered we do
16 need to.
17 I mean we have some of the same issues, again
18 high voltage issues can often be experienced within the
19 plant, and we get into that dilemma of trying to keep the
20 plant operating in the system, at the same time keeping all
21 of the turbines within the plant operating.
22 So it's that complicated multi-unit plant on the
23 collector's high voltage. You may have high voltages within
24 the collector system as the same time you have a low voltage
25 at the termination point. So we can, have looked at the

1 different load conditions. Every load condition you add, it
2 does add additional work.
3 If you're going to look at other operating
4 conditions as well, and then you really start compounding
5 that until the study can get huge.
6 MR. BLOOM: And I guess my question there is like
7 how do you strike that balance, and is there any guidance
8 that the Commission can provide in order to help you out
9 with that?
10 MR. LAVERTY: We've adopted at MISO the approach
11 of looking at peak and light load conditions, off peak
12 conditions. We dispatched the units, in those cases, at
13 their expected output, okay. So you know, wind, in a summer
14 peak case around 20 percent; peakers are on. You get the
15 off-peak case, peakers are off; wind's up around 100
16 percent. Run of the river hydro would be up as well.
17 Just setting that bracket for us was an
18 appropriate balance between looking at the situations you
19 need to look at and getting the studies done on time.
20 There's been other issues that have popped up. But it comes
21 when you're working with the interconnection customer. Do
22 you want an asset out there that can run and can be
23 profitable, or to use a not intended to be flippant term,
24 lawn ornament?
25 Okay. If it's not running, it's losing money for

1 the customer. It's not helping us out as a transmission
2 provider either. If the thing's out there and it might have
3 been fine on peak when the load was absorbing everything out
4 there, but off-peak, when you're trying to move megawatts
5 around, if it can't do it, it can't do it, and you haven't
6 helped anybody by ignoring it.
7 MR. WILLIAMS: I'll kind of talk about a real
8 world example and then talk about maybe some studies. But
9 we have a project that interconnects on a 230 kV line.
10 Pretty much a radial 230 that comes out of a fairly strong
11 system into a fairly weak system.
12 The problems we run into is at light load, but
13 when the project's not generating. So it's connected to the
14 system, taking station power and is sitting there waiting
15 for the wind to come up and begin to generate. So there's
16 no voltage regulation capability whatsoever from the
17 turbines themselves. There's some static devices and then
18 there's also some STATCOMs at the collector subs.
19 But even with those devices in the system, we
20 cannot control voltage over 105 percent over voltage. So
21 we're struggling with trying to figure out ways to manage
22 that, and then how to study that, because that's really -- I
23 mean Eric talked about light load full generation.
24 This is light load no generation, but capable,
25 energized and ready to begin to generate, because the

1 project needs to be energized in order to begin to generate
2 when the wind comes up, and the developers don't like to be
3 black.
4 So they want to be able to find solutions to be
5 able to stay connected, and then generate when the wind's
6 blowing. So I think that's another level of studies that
7 almost needs to be looked at, is the capacity nature of the
8 collector system has a tendency to raise the voltage under
9 no load conditions or light load conditions.
10 So doing a light load, very little generation or
11 no generation would also kind of bound the, some of the
12 issues that we face. I don't believe the Commission has any
13 rules that limits the studies that you do.
14 I think the Commission is concerned if your
15 studies take too long. So as you begin to add more studies
16 and more scenarios, it just elongates the process, which is
17 already, I think from a developer's perspective, too long
18 already.
19 So you know, we need to strike a decent balance
20 that looks at the needs of the system, but also balances the
21 needs of the developers, to get the projects moving forward.
22 So --
23 MR. KOSTEREV: I have a couple of points here.
24 So at BPA, we studied both on peak conditions and off peak
25 conditions, and we also looked at the winter and summer,

1 since we kind of have two peaks operationally.
2 One thing we learned over the last couple of
3 years is the need to study what we call time sequence power
4 flow. Typically, a look at a single snapshot of the system,
5 but we found that in many cases it wasn't revealing some of
6 the issues that we had, and we need to study the wind draft
7 as wind moves from the no load to full load and go through
8 all different points and start to develop vulnerability
9 along the way.
10 We've being working with Power World and General
11 Electric PSLF program to develop these capabilities in both
12 programs.
13 MS. CAIN: Did you say you call it a time
14 sequence power flow?
15 MR. KOSTEREV: Time sequence power flow, random
16 snapshots as you're ramping the wind up and you do the
17 studies along the way.
18 MS. CAIN: So you would basically power flow
19 studies of consecutive different snapshots. So this is
20 something.
21 MR. KOSTEREV: And you make sure that the
22 reactive devices switch in time and everything's
23 coordinated, because we have a lot of coordination issues
24 among the wind power plants.
25 MR. BLOOM: A follow-up. It sounds like a lot of

1 you guys try to look at some of these issues from the very
2 beginning. Do you share those scenarios or what you plan to
3 do with the generator, so they have an expectation about
4 what they're going to be getting, or is there something more
5 that you can show them, so that they understand oh, they're
6 going to look at these different scenarios, and that helps
7 me understand what I need to do with my facility.
8 MR. LAVERTY: Yes.
9 MR. BLOOM: Fair enough.
10 MR. KOSTEREV: Yes.
11 MR. ZADLO: I don't think that's universally
12 true. Some ISOs, RTOs are very good at sharing information,
13 sharing base cases. Other RTOs are just horrible, very
14 difficult to get in the power flow models, to get the
15 contingency studies, to get a clear understanding of how the
16 analysis will be performed. So it really depends, from area
17 to area.
18 MS. CAIN: Another issue that seems to have come
19 up this morning is how do the system impact studies study
20 deliverability of the generation? So it sounds like in some
21 cases you're studying can the generator safely interconnect
22 and not impact voltage. But do you study under different
23 conditions can the generator deliver its output to a place
24 where it's useful in the system? Noman.
25 MR. WILLIAMS: Effectively, interconnection

1 studies in the SPP do not look for deliverability. They
2 look for the ability to connect and generate, but not to
3 deliver to a specific load anywhere. So it's basically just
4 put on, generators' stated output, whether it's full load or
5 partial load, and just looks for the impacts, with
6 deliverability stated or implied, I guess, would be the best
7 way to say it.
8 MS. CAIN: Richard.
9 MR. KOWALSKI: And similarly, I think we are
10 doing connections. Most of our generators are pursing
11 interconnection on an energy -- for wind generators on an
12 energy interconnection basis, and it's on a competitive
13 basis. So we're never doing studies, at least within the
14 context of the interconnection studies, that look at the
15 aggregate deliverability of the projects.
16 MS. CAIN: Yes, Eric.
17 MR. LAVERTY: We look at both what we call
18 injection and deliverability. Deliverability in MISO is a
19 study we do for a network resource interconnection service
20 generator, and that's a gateway towards our resource
21 adequacy construct and ways to get paid over there. We need
22 more network upgrades. But we also look at the injection.
23 It's a term we coined after Order 2003, as the description
24 of the energy resource interconnection service said that the
25 energy had to get onto the grid, just not off at a specific

1 point.

2 So we said okay well, take out all the technical

3 terms on it. We said okay, if you're just sticking power

4 into the grid, let's make sure that the neighboring area is

5 okay. A classic example is a 500 megawatt generator

6 connecting to a 300 megawatt line. If it's intact, you're

7 probably okay. But if you use one side or the other, you've

8 got an issue there.

9 So that's looked at under both the peak and off-

10 peak conditions in MISO. We have run into some issues where

11 because our injection constraint requirement, there's a

12 higher threshold than what we're going to charge an upgrade

13 to a customer there.

14 Then you get into actual operation. They curtail

15 any lower threshold. So we've had some customers come back

16 and say what can we do here? So that there's a balancing

17 act that we're dealing with now.

18 MS. CAIN: Just to follow up, how much longer

19 does the study take for the injection study versus the

20 deliverability study?

21 MR. LAVERTY: Using the classic planning answer,

22 it depends. If your injection study resolves all the

23 constraints that the network resource study would take, then

24 it's just computer processing time, an hour or so to run it,

25 analyze it so you don't have problems.

1 If there is a difference in the required upgrades
2 between the injection and then the network resource level,
3 then that gets into how much upgrades do you have, how
4 complex are the fixes, that sort of question. It could be
5 just a couple of hours; it could be a few weeks.
6 MS. CAIN: Thank you. Rich.
7 MR. KOWALSKI: Just a point of clarification on
8 the deliverability. At least in the ISO New England
9 markets, intermittent resources are assigned a capacity
10 value, and the capacity value of wind is typically in the
11 order of about 15 percent of our onshore wind, of its
12 nameplate.
13 So we do an aggregate deliverability, but it's of
14 a much smaller amount of the capability of the wind. So we
15 never see the full name, or least in the interconnection
16 study, we never see the system challenged by the full
17 nameplate capability. We do have other system studies that
18 are exploring those possibilities, but it's outside of any
19 connection space.
20 MS. CAIN: Thank you. Anyone else on that
21 question? Yes Noman.
22 MR. WILLIAMS: I do want to add a little bit of
23 clarity also, but within the SPP, with the energy imbalance
24 market, once a generator does have the ability to connect,
25 they do have deliverability through the IS market.

1 It would be non-firm, but they do have the
2 ability to generate and sell into the market without
3 securing any transmission service or any deliverability from
4 that project.
5 We, as a stakeholder group, have gone through a
6 lot of discussion about how studies are done between energy
7 resource, network resource from an interconnection study
8 perspective.
9 There's really no difference between the level of
10 study work that's done for either one of those, because of
11 that fact, because once a generator connects, they have the
12 ability to sell into the market. And all the deliverability
13 studies really are done more on the transmission service
14 side.
15 So load is the entity that can get network
16 service, not generation in most cases. So the load is
17 looking for deliverability, and once the generator's
18 connected, then you go through deliverability study from
19 there.
20 MS. CAIN: Dmitry.
21 MR. KOSTEREV: BPA has been using network open
22 season process to determine the transmission reinforcements
23 needed to grant point to point transmission requests of the
24 wind generators, any other generators at that site. I think
25 it's also caused us to have studies. I think the

1 Commission's well aware of this and --
2 MS. CAIN: And Yi, do you have any comments on
3 what CAISO does?
4 MR. ZHANG: Yes. I have a couple of points here.
5 In California ISO, we do deliverability assessment,
6 undeliverability assessment. Deliverability assessment of
7 ISO, basically it's kind of associated with the resource
8 adequacies, to identify basically the criteria for resource
9 adequacy progress. The deliverability assessment locates
10 like- source reliability and the reactive power
11 requirements. I think that's what we would do.
12 MS. CAIN: Thank you. Any other staff have
13 questions? Dick and then Sassan.
14 MR. O'NEILL: If my notes serve me right,
15 Sunflower recommended a .95 power factor. Cal ISO
16 recommended a .95 power factor. BPA said they wanted a .9
17 power factor. He said 95? Okay, good. And ERCOT said .95.
18 Yet I heard MISO talking about determining the reactive
19 power needs at the point of interconnect, which actually
20 sounds really better than .95.
21 So my question is why .95? What's the
22 justification for .95 and why can't we do what MISO's
23 suggesting, and determine the reactive power needs at the
24 point of interconnect?
25 MR. LAVERTY: Well, we offered two proposals.

1 One was a standard. In the absence of a standard, what we
2 had suggested was to flip the question that's being asked
3 now. When you look across our footprint, .95. Point 95 is
4 the usual standard.
5 We have some areas, the lower peninsula of
6 Michigan being one, where they have a wider range required
7 there, and that's an artifact of the plants being located
8 along the Great Lakes, and then the load having to be served
9 all the way into the middle of the mitten there, and you've
10 got to have a more reactive capability at the generators
11 there to bleed over.
12 MR. JENKINS: Robert Jenkins, First Solar. I
13 think the question was why .95. I think you have to go back
14 to kind of the history of looking at conventional
15 generators, and the conventional generators it was
16 calculated, and I think they repeat the calculation in the
17 NERC report I mentioned earlier.
18 If you take the traditional reactive capability
19 of a conventional generator, and then take it up through the
20 main transformer bank, its equivalent is approximately .95.
21 So it was built off okay, what is a traditional generator
22 required to do?
23 If it's doing .9 at the terminals, what would
24 that mean at the high-sided transformer, and that's -- then
25 it assumed that the high-sided transformer would be the POI,

1 and that's kind of how you bridged from what was being done
2 with traditional generators, versus what's being required of
3 661-A.
4 MR. O'NEILL: But I think you made the point that
5 you only want to have to pay for what you need to provide.
6 MR. JENKINS: Our point was more of a binary
7 test. Do you need reactive or do you not need reactive
8 support? If you need the reactive support, we'll go ahead
9 and design for the standard, plus or minus .95, not really
10 getting into whether you need .97 or .98. That's a very,
11 I'll call it, temporal type of calculation. You might need
12 .97 this year, you might need .98 next year type of thing.
13 It would tend to move around.
14 But if you just say you need it or you don't need
15 it, have a binary requirement, and then know what your band
16 is. Okay, if you say I need it, then I know what I need to
17 provide. I don't have this uncertainty, well you need to
18 provide .85 at the POI. Well how in the world are we going
19 to do that?
20 So I'm not looking for that level of analysis.
21 I'm just looking for if we spend the money for the
22 capability, that it will be used. So the binary requirement
23 is it or is it not required, and then yes, we'll go ahead
24 and we know what the design should be.
25 MR. O'NEILL: But you said the .95 comes from a

conventional generator?

MR. JENKINS: Yeah.

MR. O'NEILL: And so you have no problems with applying a conventional generator standard to wind or solar?

MR. JENKINS: We're looking for some parity. We're also looking for some bounds. We don't want open-ended, you know, where it could become and have a requirement that it could be much, much greater than a conventional generator. But I don't think that's, you know, if it's needed, I don't think that's a unreasonable way of approaching it.

We have to upsize our AC equipment, just like a conventional generator has to upsize its state of winding, to provide reactive power. Again, I don't think that's -- I don't think it adds extra value for the amount of extra calculation it would take to go and do a lot of the project-specific. Okay, this one needs .975, this one needs .98 and this one needs .985. It's a lot of analysis it would take to do something like that.

MR. ZHANG: This is Zhang, California ISO. Just like Robert mentioned, there's some historical reasons for the .95 requirement. But I would like to add something from our experiences. Point 95 power factor, although we ask for that, but it doesn't mean .95 power factor will solve all problems.

1 In our study, there are many areas. But although
2 we model a .95 power factor for all generators in those
3 areas, we may still need additional reactive power devices,
4 including some capacitor on the ICCLU (sic) and STATCOM, to
5 maintain the system reliability.
6 Another thing is I think the current technology
7 in provide wider power factor rings, not only primary power.
8 If the developer like to provide the .9 power factor, I
9 think we also take it.
10 MR. O'NEILL: Thanks.
11 MR. KOWALSKI: Rich Kowalski, ISO New England.
12 Again, if we're talking about .95 power factor, one thing to
13 keep in mind too, I think it's still just a steady state
14 value. We've got experience that suggests that a dynamic
15 power factor actually needs to be a little broader than
16 that.
17 MR. O'NEILL: When you say "dynamic," I've heard
18 that term a lot, and I'm not sure where we put the dividing
19 line. Everything is dynamic to a certain extent, I believe.
20 MR. KOWALSKI: True. When I say it, I'm thinking
21 in terms of the system in steady state, you know. If
22 something happens, the dynamic power is getting to the next
23 steady state, and at that next steady state, you know, where
24 I think about the .95 power factor, it's all right. From
25 where I started to where I need to where I land. You know,

1 that's where that .9 power factor.
2 But in between, you know, when you have a fault,
3 when you have an event, the system swings around the actual
4 reactive capability out of a conventional generator goes
5 outside frequently, much further outside .95. And when that
6 capability isn't there, I mean we're also seeing the
7 consequences of that.
8 In the, coming back to our experience on the .95,
9 you know, we've got a lot of system. Historically, I agree
10 with what's been suggested. .95 seems to be what was
11 capable, what the system could provide, what the system
12 could move, what it would take to support the power system,
13 and again, what's the power system? It's really moving
14 generation through the transmission of the load.
15 So it's that the voltage, the dynamic capability,
16 the steady state capability supporting the ability for that
17 generation to operate, and you know, if we look at the
18 scenario -- if we look scenario-specific over the evolution
19 of the system, I think we would have a different system.
20 I don't think -- I don't know that scenario
21 studies would show that you necessarily need a .5 power
22 factor. In some cases they would, unless you really studied
23 the broad scope of what operation, the operation of the
24 system really exposes you to. Again, that's been our
25 experience.

1 If you put the blinders on, some narrow
2 conditions that are consistent with the TPL standards,
3 consistent with conventional planning, you know, even over a
4 range of load levels, you're still not going to capture
5 everything that the power system has to ride through.
6 And again, our experience in having plants
7 connecting this way, to a minimalistic case-by-case, proved
8 just -- proved to me what you need to add in terms of
9 reactive support, ends up with a generator that can operate
10 at its capability in a very narrow window of operation.
11 Take a line out of service, immediately you're challenging
12 that capability.
13 And again, our experience is we have plants that
14 are subject to significant restrictions, with what in the
15 past we would have viewed or had been viewed and experienced
16 as fairly small outage conditions, normal line maintenance.
17 Our one power plant has more operating guides
18 than any other power plant on our system, including our
19 1,200 megawatt nuclear plants. So the consequence of
20 building to having no margin creates a system where you have
21 no margin, and there's a consequence both to the generator
22 and the ability to operate that system, and operate a
23 population of wind generators on that system.
24 MR. ZADLO: This concept of high voltage problems
25 or low voltage problems, it predates the renewable business.

1 Back when I was at the utility, Easter weekend was the low
2 load period of the year, and in order -- and the voltages on
3 the system were sky high, and we would have to take lines
4 out of service. We'd have to open bus tie breakers and
5 what-not in order to keep the voltage down. Back then, you
6 had just a classical vertically integrated utility.
7 Then going into the summer, we would make sure
8 that every capacitor bank was online, serviced and ready to
9 go, to help with the summer peak, right? So this light
10 load, heavy load scenario, it predates wind, and it's going
11 to continue being an issue when we're onto the next
12 generating platform.
13 I think the issue in front of us is how do we
14 efficiently and cost effectively plan the grid for its
15 reactive power requirements? And I don't think, speaking as
16 a wind developer, I don't think we're opposed to providing
17 reactive, additional reactive power support.
18 It is an additional cost. All we're saying is
19 just provide us the study. Show us the study, and I think
20 that's fair not only for renewable resources, but all
21 resources, because that is an added cost when you're
22 developing a generator.
23 MR. O'NEILL: Just to be clear, I'll show you the
24 study. I'm sort of getting some mixed messages. Mr.
25 Jenkins says if we need reactive power, we'll go to .95.

1 But then, you know, and then is that acceptable? Then if
2 suppose the study says we need more than that? Is that
3 acceptable?
4 Yeah. In ERCOT it sounded like the .95 was
5 sacrosanct. Maybe that was the way I read what you said.
6 But you know, what if it's .90?
7 MR. ZADLO: Right. Well, I mean let's look at it
8 differently, okay. Would it make sense to require every
9 substation to have 100 megawatts of capacitor banks? That
10 would be silly. There would be an additional cost to the
11 consumer, right, for you to install a reactive device
12 everywhere on the grid, right? There's a cost there, cost
13 causation.
14 There's that same cost happening when you impose
15 that requirement onto generators. You're requiring them to
16 provide reactive power, okay. So just as you do reactive
17 planning for your system, or you've done it before 20 years
18 ago, you make a determination whether this substation needs
19 100, you know, whatever the value is, capacitors; this one
20 doesn't.
21 You've done that analysis before. You could
22 perform that analysis for generators. Not every generator
23 is going to have the same impact on the grid. It has
24 different -- it just has a different impact.
25 MR. JENKINS: Going to your question, I feel like

1 if it -- well traditionally, reactive power planning looked
2 at okay, did generators have the capability of what they
3 have, and then you look at the optimal location for
4 additional reactive resources.
5 I don't want to find ourselves in a paradigm
6 where we say well, the reactive resources have to come from
7 the generator, and we'll just keep turning up the reactive
8 requirement of the generator, without stepping back and
9 saying well no where's --
10 Like we said, reactive is very local, and each
11 incremental megavar you generate at the generating sites
12 will have a diminishing return. So just amping up the
13 requirement of the generator is not likely to give you the
14 best answer.
15 I think it's much clearer if we just say okay,
16 this is the generator requirement. If the additional
17 reactive resources are required, this has been -- the same
18 is true with conventional generators, then you look at your
19 whole system and identify where do we really need to site
20 reactive power?
21 Part of our planning studies for the utility, and
22 say okay, we need a cap bank here; we need a reactor bank
23 there for off-peak conditions, and you address your reactive
24 power needs through traditional system planning methods.
25 But you know that the generator, if you've

1 identified through a study that needs to provide reactive
2 power, that yes, it will provide up to the typical
3 requirement or typical capability of a generator, and it's
4 the same as conventional generators as it would be for non-
5 conventional generators.
6 MS. CAIN: I think we've had several hands
7 raised. Dmitry and then Jeff and then Richard Kowalski?
8 No. Okay, so Dmitry and then Jeff.
9 MR. KOSTEREV: Yes. So the FERC LGA requires
10 conventional generators provide .95 power factor at point of
11 interconnection. So that's kind of a baseline, and I just
12 want to clarify BPA requirements. We're asking for .9 power
13 factor not at the point of interconnection, but at the 35 kV
14 substation.
15 Then in addition to this reactive, switch
16 reactive shunts, you know, to compensate for reactive losses
17 between the 35 kV bus and the transmission system.
18 MR. O'NEILL: So I did hear you right. You said
19 .9, but it was at the wrong place.
20 MR. KOSTEREV: Well, by the time we get the point
21 of interconnection through the .95, because you're
22 compensating for the losses, yeah.
23 MR. O'NEILL: Okay. I just -- okay.
24 MR. KOSTEREV: Then again, we've done studies,
25 you know, hub studies to determine that, I mean the

1 requirement. Another point I want to make, and I mean I
2 think Richard made, he made a very good point. Every time I
3 talk to our operations guys about the new plan of service,
4 they keep reminding me of the need to have operational
5 flexibility.
6 We do studies under the condition that rarely if
7 ever exists in our system. That's condition all lines in
8 service. You go in a typical operating day, you may have
9 five, and during the maintenance period you may have 20
10 lines out of service. So you need to have the capacity in
11 the system to be able to operate in those periods, when you
12 have either forced or maintenance outages.
13 Part of the strategy is having the uniform
14 requirement for all the generators, so you're not dependent
15 or not changing your operating procedures on a minute to
16 minute basis, based on the outages on the system.
17 MR. O'NEILL: So you consider transmission
18 maintenance voltage requirements the responsibility of the
19 generators?
20 MR. KOSTEREV: Well, the transmission outages,
21 they will potentially cause curtailments of the generators
22 if there's not enough reactive capability to --
23 MR. O'NEILL: That's an important point. If
24 they're going to cause a curtailment of the generators, then
25 that's probably of great concern to the generators. But if

they're not going to cause curtailment of the generators, or at least the ones that you're studying then, putting the blame on them or putting responsibility on them seems, I mean I don't know why that would be the case.

MR. KOSTEREV: Yes, I understand now.

MR. KOWALSKI: And if I might add to that, again that in fact has been our experience, is the generators that are planned into the system using the .95 power factor are more robust. Not that, you know, it eliminates the need to do operational planning studies and identify supplemental reactive controls in other parts of the system.

But if you just look at those limited scenarios, and if you only have a generator that's got a reactive capability that's defined based on limited scenarios, when you get into those actual operating days, where you've got multiple lines out of service and maintenance periods, the curtailments that we're experiencing are dramatic.

Again, you know, we've got plants that are cut down to 25 percent of their capability, and that's with a large number of possible line outages. So again, there's a lot that you don't realize that you've gained by having this margin, until you live in a paradigm where you don't have the margin, and everything matters.

You take a line of out service and now this plant's down and that one's down, and that's if you've got a

1 planned condition. So you know, it's one of those things.
2 Again, you know, historically we've had experience in
3 planning the system and operating the system and done
4 studies with certain expectations, with that certain
5 capability being there, that you get from the dynamic
6 capability of the synchronous generators.
7 As you start eroding that, before you know it,
8 you're in a situation, where they can't -- the plants that
9 are online, which are the wind generators, can't operate,
10 because they don't have -- they're not bringing that same
11 blatant capabilities to the table, and they're basically
12 undermining their own ability to operate under the broad
13 range of system conditions that we actually live with on a
14 day-to-day basis.
15 I mean that's the thing, is every day, I think we
16 have six lines out of service. Every day. That's on
17 average, on the maintenance periods, it's even worse. So
18 that becomes the operating reality, and you know, when the
19 generators are coming online and all of the sudden being
20 subject to that, they realize oh, you know, this is a
21 problem. What can I do to fix this?
22 But after that, they're losing millions of
23 dollars a day. So there's a consequence to them, and again,
24 you know, we talk about the system and operating the system
25 and voltages on the system. That's needed to move the

generation.

MS. CAIN: I think Jeff and then Yi, were you raising your hand earlier? Noman, you were though. Okay. So Jeff and then Noman.

MR. BILLO: Yeah. I'd like to take that thought a little bit further. If you think about a plant, a generation plant, it's going to be on the system for 20, 30, you know, 40 years or longer, and to study that plant a few years before it comes on the system, and not study to determine what the reactive capabilities are going to be for the next, you know, 30-40 years, that's just not a viable way to plan the system.

And you know, if you think about the .95, there's nothing sacred about the .95. It's a number that sort of evolved over the industry, over the years to the industry, that the wind and inverter industries have responded to that and have come up with technologies that can support that standard.

You know, the approach that we've taken has been more of a partnership, where the generators partner with the transmission to supply the reactive needs on the system, and the approach that we've taken is that the generators will supply that .95, and then any reactive needs beyond that, then the transmission system will take care of that throughout the life of the plant.

1 MR. WILLIAMS: You basically said what I was
2 going to say. You know, .95 is a trade-off, and it has, you
3 know, just has grown up in the industry. You know, if you
4 look at where wind technology started, it was induction
5 motors, which really didn't have the ability -- or
6 induction-type machines didn't have the ability to provide
7 much reactive. So they were more induction rather than
8 capacity.
9 And so, you know, you tried to compensate them to
10 a point where they weren't degrading the system, and then
11 the technology has come where they can begin to provide some
12 additional capability than what they've had in the past.
13 But I think the other thing we need to remember about the
14 system that a lot of the renewables are connecting to today,
15 is the system is out in the middle of rural areas. It was
16 not built to provide generation services; it was providing
17 load services.
18 So it had a specific balance, reactive balance
19 and capability put into it that was inherent in the system,
20 because it was lightly loaded. But also, so it had a fair
21 amount of margin. So you take a line that was built to
22 service 20-25 megawatts of load, and now you put a 100
23 megawatt wind farm on the end of it, you've changed the
24 characteristics of that system.
25 And you're trying to take the margin out of it to

1 deliver the renewable, without investing a lot more
2 infrastructure around it. So there's got to be some trade-
3 offs, and there needs to be some capabilities incorporated
4 in with the interconnection that provides some of that
5 reactive balance.
6 So you know, doing the planning around that takes
7 a little -- it's a change in thought process for a lot of
8 folks, because now you're moving from, you know, central
9 station power, which had lots of transmission built to
10 support it, to a dispersed, more dispersed larger block of
11 energy, but it's connecting to systems that weren't designed
12 to be generation delivery. They were designed for load
13 delivery.
14 So we've got to step back and look, and basically
15 look at the whole system again, and determine ways to
16 efficiently and effectively allow for interconnection,
17 provide load service, maintain the reliability, which
18 includes bringing the reactive components into the overall
19 mix. So it's a change for the industry, too.
20 MR. BLOOM: I hear what you're saying there,
21 Noman, about we've got this change in the system. But what
22 it sounds like is that, you know, we've really got this
23 need. We can show that we have a problem, that we really
24 need this voltage support. But why does the system impact
25 study fall short of providing you the type of evidence that

1 you need to place a requirement on the generators, to
2 provide the reactive power? What is the missing link that
3 doesn't allow you to take, oh real world experiences, we've
4 got problems, and say guys, we need you come up to the table
5 with these reactive capabilities?
6 MR. WILLIAMS: Give me a minute to think about
7 that one.
8 MR. KOWALSKI: I'll volunteer. I think in the
9 system impact studies, we don't anticipate or expect doing a
10 broad range of what amount to operational analyses, and
11 anticipate all of the possible operating conditions that the
12 plant could be subject to. That would be a huge, huge type
13 of study to embed in an interconnection study.
14 MR. KOSTEREV: This leads to the question that I
15 had, and I think it's an important question to discuss, is I
16 think it's when we put together feedback on if they were
17 going to do a system-backed study, case by case basis, and
18 cover a variety of the system conditions, including a min
19 load, light load, time-sequenced power flow, taking into
20 account voltage potential, delivery of power to a large,
21 another area, voltage issues, things that you experience in
22 the operational world, can you give us a sense that if a
23 system's impact study in a case-by-case basis, was going to
24 encompass all those scenarios, to give us the answer that
25 what would be the reactive power.

1 How much time would such a study would take, and
2 in the reality that we have today, that's I think the 30 or
3 45 day limit that tried to turn around the system impact
4 study, take into account that that system impact study may
5 be performed for a unit that may have had five places in the
6 queue to hold. What if I want to put it here and here and
7 here?
8 I think if you can give us that flavor, that a
9 good, detailed system impact study, which is separate than a
10 very detailed reactive power planning study, what kind of
11 time would it take to perform that kind of a system impact
12 study? That would lead to, I think, understanding that
13 maybe the limit that we're talking about is just the
14 duration that a detailed system impact study would take.
15 Can you help us with that?
16 MR. KOWALSKI: I mean from our experience, in
17 actually having to develop some of the operating analyses,
18 we're talking probably many man months. Many man months.
19 MR. LAVERTY: If you'll allow me to blatantly
20 answer a different question, that's easier to answer on
21 that, in 120 days, we're able to cover peak, off-peak,
22 thermal stability, short circuit, with system intact, first
23 contingency and selected second contingencies.
24 Where the operating realm is discussed, you're
25 going out to six, seven, eight, nine contingencies which is,

1 you know, if I remember my math correctly, that's a
2 factorial expansion of the amount of scenarios you have to
3 cover. Then you've got more load things on that, so that's
4 additive as well.
5 So what I can tell you is in four months, we're
6 able to do the two load scenarios under 0, 1 and 2
7 contingencies, along with our stability and thermal.
8 MR. JALALI: And you are not doing the time
9 sequence power flow that Dmitry discussed? That's not
10 covered in that?
11 MR. LAVERTY: No, but I might have one of my very
12 smart engineers give him a call later, after this
13 conference, to hear about that.
14 MR. ZADLO: As I mentioned in my opening remarks,
15 we've developed 30 wind parks across the U.S. None of them
16 in New England, but we have not experienced the issues or
17 problems that Richard has mentioned. In fact, it's the
18 other side of it, where we interconnect and we have
19 interconnections both in the WECC as well as ERCOT and in
20 the Eastern Interconnect.
21 What we find is the grid voltage is very tight.
22 We peg out on reactive capability. It's either we're all
23 out or all in, when we're trying to meet our voltage
24 schedules. You know, so I really don't see the problems
25 that Richard is mentioning.

1 The other thing is there's always a tension
2 between transmission planners and operators. Operators
3 always want a more robust system. They would like to have
4 the transmission system planned out for two, three, four
5 contingencies, and transmission planners know that they
6 can't justify a system like that. They have to justify it
7 prudently, and it's usually N minus 1, N minus 2.
8 So six lines out of service, 12 lines of out
9 service during the off-peaks, yes, that's typical. That's
10 what happens on our grid across the country, and operators,
11 both on the transmission side and generation side, need to
12 deal with that.
13 There's a good experience I want to share with
14 y'all, that there's a prolonged outage on the grid right
15 now, where our wind facility is interconnected at the end,
16 and that transmission provider is allowing us to operate our
17 facility above the power, above the voltage rate. It's like
18 1.05. They're letting us operate to 1.08.
19 So there is flexibility and capability in the
20 grid to handle something outside of kind of, what's been out
21 there for years.
22 MR. JALALI: Thank you, Kris. I think that just
23 to get at least understanding on this, the time that it
24 would take to perform a comprehensive system impact study,
25 so questions like that can be answered, is why system impact

1 study fails to identify the reactive power need, and then
2 later on you have to go to reactive power planning?
3 I think Eric mentioned that when they do their
4 studies and they believe it's a comprehensive system impact
5 study, it covers, takes about 120 days, I'd like to pose
6 this question also to others who perform system impact
7 studies. I know Jeff and Dmitry have performed and I think
8 Noman, have performed themselves system impact studies.
9 I'd like to get your perspective. If we were
10 going to perform a system impact study, covering a variety
11 of these load conditions, load ramp, lean load, light load,
12 capturing the various systems that they believe
13 representative, what kind of time are we talking about, such
14 a system impact study would take for one wind unit?
15 MR. BILLO: Well, I'm going to somewhat avoid
16 that question, and the reason being is I think going back to
17 what I said earlier, even if you could plan an infinite
18 number of operational scenarios, that still does not take
19 into account the changing system that we're seeing.
20 And going back to my example earlier, as we're
21 seeing in West Texas, you know, five or six years ago nobody
22 would have believed me if I would have stood there and said,
23 you know I think some day, we're not going to have any
24 synchronous generators generating in West Texas.
25 I think that we're going to see days where 25

1 percent of our demand across our interconnect is being
2 supplied by wind. Nobody would have seen those, foreseen
3 those types of things five years ago. So it's not just
4 looking at the operational studies; it's looking at what's
5 the reality of the system over the life of that plant, and
6 that's something that is hard to foresee ahead of time.
7 MR. KOWALSKI: Again, it's probably I'm not
8 trying to advocate that we, you know, expand the number of
9 studies to cover all the possibilities, because as Jeff
10 indicates and I agree, is you can't. There are just too
11 many possibilities, and it's really not practical to
12 envision a paradigm where you're studying every possibility.
13 That's one of the things we gain, by having some
14 latent capability and margin in the system. And our
15 experience, I point out, is really illustrated is in most of
16 our circumstances, we're operating with generators with .95.
17 A limited number of studies works; operating studies are
18 reasonable, still with some restrictions.
19 But where we have plants interconnecting that
20 have no margin, it's a disaster. So that's that stark
21 contrast that we've learned through this experience of
22 system interconnecting with margin versus not. And again,
23 partly it's partly the nature of the New England system.
24 MS. CAIN: I think Yi had a comment, and then
25 we'll go to Robert and Kris.

1 MR. ZHANG: Yeah. Talking about the workload,
2 I'm an engineer and basically it's my dirty job to run the
3 studies. But to be honest, I really cannot remember how
4 much workload it will be, because I only remember that I run
5 study every day, and run study and not finish and then
6 another study is started and we restarted.
7 There is a lot of workload, no doubt about that.
8 But I would like to clarify this. The current system impact
9 study, it practically it's nothing wrong with the technical,
10 the system impact study to identify the reactive power need.
11 The problem is, as I mentioned earlier, is
12 there's some drawbacks. We cannot say it's failed because
13 there's some drawbacks. It's not sufficient, and also the
14 facts are for the study results shows us along with the
15 connection, the total capacity increase, the most new
16 generation interconnection requires, even based on the case-
17 by-case approach we already identified they need to provide
18 reactive power capability. I don't think there's really
19 much exception.
20 Inefficient it is, I think for many utilities and
21 ISOs have the same feelings. It's not efficient at all. We
22 need a lot of restudies and basically it's a very -- not
23 only time-consuming, but also wastes a lot of time. And
24 also that one should recollect that it's a lot of potential
25 unknown in the studies. That's big risk to study, and also

1 drive like of the whole process. That is what I want to
2 clarify.
3 MR. JENKINS: Going back to my old transmission
4 planning days, as Chris said, typically you study what you
5 perceive the boundary conditions to be, study the peak
6 conditions, off-peak conditions, certain sections of the
7 system. We even study a spring partial peak case for
8 certain operational reasons.
9 But in order to keep things manageable, you have
10 to keep the number of cases you study fairly reasonable, in
11 order to process them all through. I mean just the graphic
12 Cal ISO showed. And also embedded in this graph is a great
13 deal of uncertainty as to which of these resources we'll
14 develop.
15 There's going to be only a small percentage
16 developed, and you're trying to do a lot of analysis on our
17 curve. So what we would normally do is we would study the
18 extreme conditions, and that would catch most of you, if not
19 all your problems.
20 But you would still have your reactive power
21 planning study processes. This is outside the
22 interconnection process. You study the generators and you
23 make those decisions and you move forward.
24 But then you still do reactive power planning for
25 your system. If you find certain sections of the system

1 that need additional reactive support, reactive support does
2 not take that long to install. It's fairly quick, and we'd
3 study that and we would identify it. Those are general
4 system grid needs that we would need reactor support in a
5 certain area and plan for it.
6 It's part of our normal transmission planning
7 activities, and really divorced it from the generator
8 interconnection studies. You know, we would still study
9 peak, partial peak if necessary and off-peak, and look at
10 does the generator need to provide reactive power. That
11 would usually come out in those studies or not.
12 But you don't try to cover everything in these
13 studies. There's just too many of them, and there's too
14 much uncertainty in this graph. You don't circumvent your
15 normal reactive power planning studies and you identify
16 them. There are other needs in the network. You plan for
17 them and you build them. They're network upgrades.
18 MR. ZADLO: I will offer an opinion and let my
19 utility friends disagree with me. It's hard to think that a
20 voltage study will take longer than a stability study, and
21 given the local nature of reactive power, I would think that
22 a voltage or a reactive study would be somewhere in between
23 time-wise to perform, between a short-circuit analysis and
24 thermal.
25 So I don't see why this can't be performed as

1 part of the system impact studies.
2 MS. CAIN: Noman, did you also have a comment?
3 MR. WILLIAMS: I don't disagree, Kris. I mean it
4 can be. I mean I think the one thing from our perspective
5 and also from SBPs, I mean they study on impact. They study
6 100 percent output. They don't look at five percent, ten
7 percent. They're required to look at 100 percent. But
8 they'll look at various load levels on the system.
9 But it becomes a moving target. The uncertainty
10 that's built in. You take the cluster, you do the study.
11 Here's a result with this group of generators. Well then
12 all of the sudden that changes. So it's still valid. You
13 have to step back and look at it again.
14 So it becomes a question from the timing
15 perspective, is when you can you actually say this is what
16 we're going to plan for. Then once you have something you
17 can plan for, then you can do that voltage study. Then you
18 can do that short circuit study.
19 But it's getting to that point in the process to
20 say, you know, this is what we're going to do, and that's
21 different than traditional planning. Traditional planning
22 was, you know, we know our plans. We're looking at
23 uncertainties and the conditions that are going to change in
24 the future.
25 But typically, we controlled -- in the old days,

1 we controlled what was going to happen, as far as
2 generation or other things. Now, there are significant
3 external drivers to the planning process, and you're trying
4 to balance the stakeholders needs of many, many different
5 stakeholders.
6 So when you can get to that point when things are
7 -- the crystal ball is not cloudy anymore, it's a little
8 clearer, then I think you can sit down and begin to do a lot
9 of these other studies, to define, you know, what your
10 reactive is and what your system requirements are for
11 various things.
12 You know, I think the .95 or putting .95 as a
13 requirement gives you some certainty from a generator, for
14 us, from a planning perspective but also from a generator's
15 perspective, and then you do the balance of it through a
16 sustained reactive study.
17 The concern still, from my perspective, is again,
18 you're looking at applying reactive resources locally for
19 problems that are generated to serve something else, and in
20 a cost allocation, I didn't want to put this on the table
21 today, but on a cost allocation standpoint, the local
22 customers tend to pay for those reactive requirements, to
23 solve the problem that is for someone that's distant.
24 So looking at how you're going to resolve some of
25 those issues going forward, I think is another issue that

needs to be addressed, absent the technical side. But the cost allocation will become important, because those customers have already paid for their reactive requirements, and now they're being asked to pay for reactive requirements for the integration of renewables or other resources to move that energy to a distant market. So --

MR. O'NEILL: Can I ask a question?

MR. WILLIAMS: Sure.

MR. O'NEILL: If .95 is the answer, why do we have so much anxiety over doing these studies? I mean if the answer to the generator is .95, why isn't that the answer? Why do we have to do all these very difficult studies?

MR. WILLIAMS: I don't know if I have an answer to that. Richard.

MR. O'NEILL: I mean yes, I can understand that you may have to do the studies, but from the point of view of the generator, if the answer after you do the study is .95, why do you have to -- why does he have to wait? Why doesn't he just design his system to .95 and call it a day?

MR. JENKINS: Well, the question was more along the lines of is it needed as the binary question? Is the reactive support needed or not needed. If it's needed, then we'll design to .95. But again, as I mentioned earlier, we have had cases where we've connected power plants into a

very stiff system, and it really can't move the voltage, and it sits there.

Whenever it's run, either pegged high or low, depending on what the system's doing. It's either if the system's running high voltage, then the system will be pegged full buck. If the system's running low voltage, it will be pegged full boost. But they're really not moving the voltage at all, and we're just kind of the tail of the dog.

But yet we've installed equipment to go and do that, but you say well, for what end?

MR. O'NEILL: How hard is it to come to that conclusion? I mean --

MR. JENKINS: It's easy in the extremes, as opposed to if you start getting to cases in the middle. It becomes a little more difficult. But like I said for us, at least we don't ask for a lot in these studies. Just show me a case, one of the cases you've run, where you've got a problem. If we don't provide reactive support and the problem goes away, we'll provide reactive support.

Just show us the case, so that we know that what we're providing is useful to the system, and we're just not wasting money.

MR. BLOOM: So when a transmission operator comes to you and says hey, we need you to provide some reactive

1 support, what are they saying?
2 MR. JENKINS For us, we're just saying okay, just
3 show me the case and we've actually had a case where we were
4 developing a project in phases, and the first phase didn't
5 need reactive support, and the interconnection agreement was
6 signed that said no reactive support is required.
7 But when the second phase came on, well it was
8 being studied and said well, you know, the more you add,
9 then we're starting to -- problems were starting to emerge.
10 We hadn't finished the design on the first phase,
11 and we said oh, we'll go back and we'll put reactive support
12 into the first phase, because we want the system to work.
13 It's in our interest for the system to work. We don't want
14 a system that fails.
15 But we don't want a situation whereby, you know,
16 like I said earlier, we're just installing reactive support
17 for no particular need. So if they come in and say that we
18 need it, and we know what our requirement is, plus or minus
19 .95, they don't come in and say well, you need to provide .5
20 power factor or something like that.
21 We need to know something's reasonable, that
22 we're not being asked to be the long pole holding up the
23 tent of the world, but just, you know, doing our share.
24 Yeah, we'll do that. I mean we view that as being part of
25 the grid fully interconnect.

1 Now some of the other questions get into some of
2 the dimensions I discussed. Dynamic, what does dynamic
3 mean, what does dispute response mean? That's typically
4 where the richer and more interesting discussions start
5 occurring, as to really what does those, what's that
6 reactive power need to look like.
7 But it's the threshold question, do you need to
8 provide reactive power or not. I generally view it as a
9 fairly straightforward one that emerges from the system
10 impact studies.
11 MR. O'NEILL: Now the generator, the old fossil
12 synchronous generator is all dynamic, right, power? All
13 power.
14 MR. BILLO: That's correct, when it's running.
15 And there's again, different speeds of response. There's
16 lots of different flavors, and it depends on how one defines
17 dynamic, you know. I've never called a system where you get
18 some very old generators, the old excitation systems, they
19 can be pretty slow. But they're dynamic; it depends on how
20 one defines it.
21 MR. LAVERTY: You know, when I sat up here seven
22 years ago, seven and a half years ago and then you can say I
23 hear when it's needed, you know, if it's needed. One of the
24 things that I think the transmission providers up here have
25 been saying and we've been saying is we're talking about if

1 it's needed at a point in time snapshot.
2 I know in 2004 when we had this conversation, we
3 weren't anticipating, in the MISO region, 12.6 gigawatts of
4 generation retirement, possibly power replacement in the
5 2015-2016 time frame, okay. That wasn't considered on
6 there.
7 So you get into -- I don't think it's as black
8 and white as is portrayed here. There's a lot of shades of
9 gray out here, and you know, is it needed now, is it needed
10 then? Could it be needed then?
11 If it's needed then, so you don't want to get
12 into the cost allocation. We're sensitive to what we've
13 called the outer tail problem. But you know, another
14 scenario is if a generator wants to go and retire, you know,
15 and you have, which hasn't really been the case with wind, I
16 don't think, because of the location but could get there
17 with some other technologies, you got one there that you
18 didn't require reactive power and then a generator nearby
19 retires, and now you're putting in a STATCOM or SVC device,
20 because you need some voltage support in the area. So the
21 point is there's a lot of uncertainty, as you look at assets
22 that are in the field, anywhere from 20 to 70 years, and
23 we're making decisions based on just a handful of snapshots
24 in time.
25 MR. O'NEILL: So you're going to put in a

1 STATCOM? Are you going to think about a condenser,
2 converting the generator?
3 MR. LAVERTY: You have to look at it. Now
4 remember with the synchronous condenser, you've got to have
5 a fuel source there, right? And if you've got a good fuel
6 source --
7 MR. O'NEILL: Well, electricity is the fuel
8 source, isn't it?
9 MR. LAVERTY: Yeah, okay. All right. So
10 additional load on that. You've got a lot --
11 (Simultaneous speaking.)
12 MR. O'NEILL: No, I understand all that.
13 MR. LAVERTY: Like spinning magnet might be a
14 capacitor, and it might be as simple as a capacitor bank.
15 But you may need a power electronic device to resolve the
16 shutdown, and you're back to, you know, oh, I wish we would
17 have done this then. That's a hard pill for someone to
18 swallow when they're looking at cash outlay next year. I
19 get that.
20 Plus with the idea that, you know, if you paint
21 yourself in that corner, you're in that corner.
22 MS. CAIN: Do you have any other questions from
23 staff over here? Abdur.
24 MR. MASOOD: I just want to verify something,
25 just a couple of questions. All these studies you're doing,

1 are you using the nameplate rating of the wind or are they
2 separate? Okay, the other was when you're doing cluster or
3 other type of study, are you just taking that area on, the
4 geographical area, or looking at the whole system, if
5 there's some other projects? Are they updating this whole
6 model or just taking only one area and calculating the
7 reactive need of that area only?
8 MR. KOSTEREV: Maybe I can take it, can answer
9 here. So in our case, you know, the wind generation is
10 developed in one area, which is the lower Columbia. It's a
11 very short, very small area. So we're looking at the entire
12 area and connection to the 500 kV grid.
13 MR. MASOOD: It's 500 kV?
14 MR. KOSTEREV: The backbone of our system.
15 MR. MASOOD: What if you're looking at two years,
16 three years, five years into the future, there's some other
17 load growth, other generator coming, those are --
18 MR. KOSTEREV: Yeah, good question. So we have
19 also projects which are developing outside the area, and we
20 started them separately, to meet the local requirements.
21 MR. MASOOD: Okay, thank you.
22 MR. LAVERTY: This is one we struggle with,
23 seeing as we're covering 13 states and a province. So you
24 know, if you've got southwest Minnesota, northwest Iowa,
25 northeastern South Dakota, you know, that you study. But

1 does a project in Michigan really affect? So we have to try
2 to strike a balance to that.
3 As far as our big projects that are in the
4 approved plan, those go in. We have a suite of projects
5 that are not in our Appendix A we call it, but rather
6 they're in Appendix B, which we can draw from if it looks
7 like it will resolve an issue. So we take that information.
8 We do look at generation as it's coming up in
9 other areas, to the point it makes sense to do so. We've
10 got, you know, will the wind simultaneous be blowing in
11 Indiana and Iowa? That's one question.
12 Now on the eastern border of Illinois and the
13 western border of Indiana, well maybe, you know. Yeah. So
14 that's -- it's a tricky study technique that we have to, and
15 we work with our customers to explain what we're trying to
16 do. We'll take input on that.
17 MR. MASOOD: Not really later, maybe during the
18 same period, a coal unit may be coming in. They're in the
19 future also. So you have to look out for that one also.
20 There's a fossil one that's coming also into the future.
21 They're not totally gone.
22 MR. LAVERTY: It's been described. The wind
23 units are out more in the rural areas. You've got the --
24 well, I haven't seen that much coal. But gas units, so you
25 have fossil.

1 They're going to be where you've got a big gas
2 pipe crossing a big electric line, which tends to be a
3 little closer to load. Some exceptions to that, but they
4 tend to be closer to load. So we don't see as dramatic of
5 an interplay there over a 13-state region as you may expect.
6 MS. CAIN: Aaron, did you have some questions?
7 MR. BLOOM: So this will be my last one. If you
8 guys could have two things change in the system impact
9 study, just two simple things and we won't hold you to them,
10 but what are two things that you guys would like to see
11 different about the process, that would make your lives
12 easier? It doesn't have to be everybody answering either.
13 MR. ZADLO: I'd like them quicker.
14 MR. BLOOM: That's only one.
15 MR. LAVERTY: We just made a big ask on changes
16 to the process, which you, you know, granted almost all of.
17 So ask me again next April. I might have some more, but
18 since you just said to our long list, I feel greedy asking
19 for more here.
20 MR. WILLIAMS: And it's very good when the RTOs
21 are agreeing with what I would have said too. So my view is
22 we need to be able to go down and look at interconnection
23 impacts or system impacts at zero generation connected, or
24 five percent load or generation, so you can see the impacts
25 at the lower levels of generation.

1 And then spend, you know, from our perspective,
2 spend more time looking at the off from at least the
3 renewable perspective, the off-peak conditions, and do more
4 system impacts around the off-peak conditions rather than
5 the peak conditions.
6 Because that's when you're really going to see
7 our perspective. You're going to see the biggest impacts.
8 I'll throw a third one in there. As we move toward market
9 dispatch, I think looking at system impacts around market
10 dispatch, rather than around a traditional dispatch, because
11 market's going to dispatch conventional generation a lot
12 different than the way it is today, especially if you're in
13 a, what I would say a constrained region.
14 We have a significant amount of renewables, with
15 a small amount of conventional resources. What's going to
16 happen with the dispatch, and then the impacts around that,
17 that market dispatch?
18 MR. ZHANG: Since today we are discussing the
19 reactive power requirement, obviously I hope we can have
20 that uniform requirement. But it is not necessary to make
21 our life on the job easier.
22 As we reduce workload here, so we still have a
23 lot of other things to do. Like we can shift our time and
24 resource to other studies, to identify the system
25 reliability and stability boundary, and to cover more

1 scenarios on different things on grid power related to
2 renewable intermittencies. So that's what I'll say.
3 MR. LAVERTY: I actually do have an ask here, and
4 the LGIP outlines the procedure or the process of going
5 through the interconnection, but it doesn't necessary spell
6 out the methodology of how the analysis will be performed.
7 Some RTOs or utilities have a good business
8 manual on that. I think PJM may be one of the better ones.
9 They have a business manual as to, you know, how will the
10 cases be developed? What scenarios will be studied?
11 I think if I would have an ask, I would ask that
12 there would be a methodology there, a clear, transparent
13 methodology and not so it's so black box, because in some
14 utilities, it's really black box how we get studied.
15 MR. KOSTEREV: A couple of things, lots of
16 studies. I think that's important for developing a 1,200
17 megawatt hub. It doesn't make sense to study them
18 sequentially. You want to study them as one project, to
19 enable the coordination among the individual plants. Also
20 coordination with existing reactive resources.
21 Second, uniform requirements, and maybe there
22 needs to be some type of threshold for the -- based either
23 the connection voltage or the size, because if project goes
24 in a , it can be grid, main grid.
25 It makes sense to have uniform requirements. If

1 a project, as we discussed, goes into some small system,
2 well you may want to start the requirements local, and maybe
3 we need to draw this distinction, based on the HV or
4 subtransmission interconnection.
5 And also going beyond .95, .95 is just one
6 aspect. As Robert pointed out many times during the
7 discussion today, it's also the response time, how much of
8 the capacity is dynamic, whether you control high-side
9 voltage or the control the droop. Those kind of questions
10 need to be addressed. I understand IVGTF is taking a pretty
11 significant step in that direction, so more to continue.
12 MR. JENKINS: Since you said what and not how,
13 that unfetters me a bit. One thing I would -- or a couple
14 of things I'd like to see in the system impact studies.
15 When we receive a system impact study today, in many areas
16 it's rife with uncertainty. It's got like a cluster study.
17 You're in there with thousands of other megawatts.
18 In your heart of hearts, you know that ten
19 percent or less are going to develop. So you get a study
20 back and you look at it, and you say what am I going to do
21 with this information, and you're really not certain what
22 you have when you have a system impact study.
23 So what I would like to have is I would like to
24 have a system impact study that would be more reflective of
25 what the ultimate system buildout would actually be. That's

1 the what. Now how? That's the trick. I'm not sure how we
2 get there. I have some ideas, but that's the what I'm
3 looking for.
4 Because when I get a study today, I'm not really
5 sure what I've got, because I know it's an answer, but it's
6 going to change. It's going to change substantially; I just
7 don't know in what way.
8 MR. KOWALSKI: If I had an ask, it would be for a
9 uniform standard, for dynamic control. As Dmitry suggested,
10 perhaps depending on voltage class. I know that's one of
11 our challenges, if we've got facilities connecting to long
12 115 kV lines, and that's where we're seeing the issues.
13 MS. CAIN: I have one specific question for Mr.
14 Jenkins. You mentioned that there's a difference between
15 wind generators and conventional generators on where the
16 reactive is measured. One was at the generator terminal and
17 one was at the point of interconnection. Is that something
18 that's just traditionally done, or is that coming out of a
19 Commission rule somewhere?
20 MR. JENKINS: If you look at the standard LGIA,
21 it has it measured at the generator terminals. If you look
22 at 661-A, it has it measured at the point of
23 interconnection. So it's coming out of the Commission's
24 docket.
25 MR. KOSTEREV: My memory serves me different. I

1 think .95 is at the point of interconnection for the
2 conventional generators. Maybe somebody's not applying the
3 rule book here.
4 MR. JENKINS: Just I think it's Section 9.6, I
5 believe, that the standard LGIA has the power factor
6 requirement.
7 MR. LAVERTY: I recall working on our older 2003
8 compliance back when I was an engineer, and our old tariff
9 required a rate of requirement at the generator terminals
10 and the pro forma had moved it to the point of
11 interconnection. I remember an hour-long argument with my
12 boss and his boss over what exactly that meant. So that was
13 just how I remembered the change.
14 MR. JENKINS: I was looking at it recently in the
15 pro formas that I have, and the conventional generators are
16 at the generator terminal, which is an undefined term.
17 MS. CAIN: Thank You. One other last question.
18 We've heard from a couple of people that we should do a
19 market -- I think Noman was mentioned we should do a market-
20 based dispatch to the generators that we use in the study.
21 What are all of you doing in your system impact studies? Is
22 it just an assumed dispatch to generator, or is it based on
23 market prices. We can start with Noman.
24 MR. WILLIAMS: Well, the standard studies take a
25 standard SPV model and we'll adjust for known factors to the

existing dispatch, and then as they load the generators in, they will load them in and dispatch them at nameplate for the impact study, as required by the process.

So and then modify dispatch around that, if necessary, in order to get the model solved. But they'll keep the requesting generator at full nameplate.

MS. CAIN: Okay. So the requesting generators are at full nameplate, and the others are just modified around to accommodate that?

MR. WILLIAMS: If required. If there's not a place they can sync the generation.

MS. CAIN: Okay.

MR. ZHANG: In California ISO, we modeled -- we have deliverability study, undeliverability study. In deliverability study, we model renewable generation different from their P max. For other PV, we will -- -- I cannot remember, but that number is around 60 percent.

It's produced based on the historical data in the same area. If in a certain area there's wind and solar we have some different numbers in our tariff. But the deliverability study, we model all generator at their P max.

MR. LAVERTY: We have this discussion at the end of every study with many developers. We don't use a market dispatch per se, because that would imply a security-constrained economic dispatch, which would require the

1 curtailment for their generators. Now while that may happen
2 in real time, in real time that's based on price and
3 transmission availability.
4 What we're studying at the interconnection phase
5 is interconnection service. So what we do is for each
6 limiting element and contingency pair, we ramp up the
7 generators that impact those, that limiting element
8 contingency pair, to their level of interconnection service,
9 either what they have, if they're -- or in service, or what
10 they're requesting, and we look for problems at that point.
11 MS. CAIN: Thank You. Dmitry?
12 MR. KOSTEREV: We do pretty similar stuff. We
13 dispatch wind generation at the full megawatt output, and
14 then we redispatch generation in the area, local area to see
15 the impacts.
16 MS. CAIN: And Richard?
17 MR. KOWALSKI: Yeah. For the wind generators
18 that are generally interconnecting on an energy
19 interconnection basis, they can interconnect and displace
20 other generation, and that's how it's modeled.
21 For capacity value, it has to be simultaneously
22 deliverable with other capacity resources, but at their
23 capacity value, which tends to be about 15 percent or so of
24 nameplate.
25 MR. BILLO: We use a standard off the shelf case

that has a purely economic dispatch end, and then if the transmission utility or the generation customer want to modify that dispatch, then You know, we'll entertain those thoughts and try to come up with something that everybody agrees upon.

MS. CAIN: And our generators, do You have thoughts on how the dispatch is modeled in this impact study?

MR. ZADLO: I think it goes back to my comments initially that the base cases should be realistic, and unrealistic stress cases really don't provide much value. I'm trying to remember, but I think PJM, in their business manual, what they do is not only do they output your generation that is -- you're proposing, but I think within five or ten buses, they also dispatch that generation as well.

That can lead into some quirky results. So if they're doing a light load study, and within a coupe of buses you have gas generation, they have a light load case with this pocket of gas generation, it just doesn't make sense. It comes up with nonsensical overloads that would never happen in reality in a light load case. So I think it just has to be a reasonable methodology.

MR. JENKINS: What we're finding more and more is financing entities are very concerned about understanding

1 curtailment risk. So what we need to have is we need to
2 have a reasonable set of adverse cases, but we also need to
3 have sufficient information that we can assess curtailment
4 risk for a particular generator, because with the project
5 finance project, that can be a major sink or swim type of
6 question with respect to what is the risk of curtailment.
7 It's not so much is there risk/no-risk, or is
8 there some risk; it's just, you know, to quantify how much
9 it is. So you can load up a case with a very adverse set of
10 conditions, turn on all the generators and have a very low
11 curtailment risk.
12 Which quite frankly makes it easier for the
13 financing, but I'm not sure it's the right answer. Is that
14 the best investment overall in the transmission grid, to
15 have a grid that is so robust that your chance of
16 curtailment is practically zero? It sounds like a very
17 expensive grid to me.
18 But we just need to -- but we need to be able to
19 -- if it's going to be something less than that, we need to
20 be able to understand and quantify it, so that we can
21 actually finance the projects.
22 MS. CAIN: Any other questions from staff? No.
23 Okay. Well, it's just about 12:15, so I think we'll wrap up
24 our morning panel. We'll break for lunch, and we'll resume
25 here in an hour, at about 1:15, and we'll start our

1 discussion of reactive power characteristics with different
2 types of resources.
3 For those of You who aren't familiar with the
4 area, you can ask any member of staff, and we'll let you
5 know some options for lunch. We have this one nice caf
6 here in the building, and there's a variety of restaurants
7 at both ends of the street. Thanks.
8 (Whereupon, at 12:15 p.m., a luncheon recess was
9 taken.)
10 MS. CAIN: I think we're ready to get started.
11 Welcome back this afternoon. This morning, we discussed the
12 studies to determine reactive power needs, and this
13 afternoon we'll focus on the different resources that
14 provide reactive power. Our goal is to gain a better
15 understanding of the technical characteristics, costs,
16 availability and options for different power resources.
17 As with this morning, we'll have each panelist
18 give five to ten minute presentation, and then we'll have
19 questions and answers with staff. I'd like to introduce our
20 second panelists. There's many familiar faces from this
21 morning, but also a few new ones.
22 We have Robert Nelson from Siemens Wind Turbines;
23 Kris Zadlo from Invenergy; Robert Jenkins from First Solar;
24 Michael Jacobs from Xtreme Power, and also representing the
25 Electricity Storage Association; Khaled Abdul-Rahman from

1 California ISO; Eric Laverty from Midwest ISO; Dmitry
2 Kosterev from Bonneville Power Administration; and Jeff
3 Billo from ERCOT.
4 So for our first presentation, Robert Nelson.
5 MR. NELSON: Okay, thank you. Thank you for
6 allowing me to address the Commission. My name's Robert
7 Nelson. I'm a Senior Expert Engineering Manager in Siemens
8 Wind Power, where I have the position of Manager of Codes,
9 Regulations and Standards in the Engineering Department for
10 Siemens Wind Turbines Americas.
11 Specifically, I have the responsibility for
12 analyzing and complying with interconnection requirements
13 for projects throughout the Americas region, including the
14 U.S., all of North America actually, Canada, Mexico and
15 South America, specifically Brazil, and the Caribbean and
16 the Hawaiian Islands.
17 I have roughly 30 years of experience in
18 transmission and generation, including work as a system
19 planner for a large northeastern utility in New England.
20 Operations engineer for Utility Power Pool, a designer of
21 synchronous machines and excitation systems and as a FACTs
22 applications engineer.
23 I was a member of the NERC Integration and
24 Variable Generation Task Force Working Group on reactive
25 power, and I'll be giving a presentation at the upcoming

1 AWEA show on wind turbine voltage regulation. I personally
2 have performed site-specific studies for reactive power
3 requirements throughout the years. Up until about ten years
4 ago, there was no uniform requirement for reactive power for
5 synchronous machines. They're all different.
6 All reactive power requirements were determined
7 either by site-specific policies or by local utility
8 policies. My company, Siemens, manufactures wind turbines
9 in the 2.3 megawatt and higher range. We're a major
10 supplier of wind turbines within the Americas, with an
11 installed capacity of over 5,000 megawatts in the U.S. and
12 over 600 megawatts in Canada.
13 Over 90 percent of these are the full converter
14 type. We have sold wind turbines of the full converter
15 design almost exclusively for the last seven years. Before
16 then, the company, then called Bonus, a Danish firm, sold
17 induction generator wind turbines. There are several
18 hundred megawatts of Bonus induction generator wind turbines
19 installed in the U.S., principally in Texas and California.
20 These turbines and parks are not designed to
21 provide reactive voltage regulation, but the overwhelming
22 bulk of the wind turbines we have online in the U.S. are the
23 full converter design, which inherently have dynamic voltage
24 regulation capability, both at the turbine level and at the
25 park level. Greater voltage reactive capability of our wind

1 turbines corresponds to roughly half of the real power
2 output, when measured at the terminals of the machine.
3 For example, a three megawatt turbine can produce
4 between plus 1.5 megavars to minus 1.5 megavars at the
5 terminals of the machine, at rated voltage. At the park
6 level, our park controllers can control the turbines to
7 provide reactive voltage regulation or reactive power
8 control or power factor control at the transmission
9 interface.
10 Many of the turbines have the capability to
11 provide reactive power, whether or not they are generating
12 active power. That is, they can operate in a synchronous
13 condenser mode when the wind speed is below cut-in speed or
14 over cut-out speed.
15 Although we'd like to think we do it better than
16 our competitors, we will note that our competitors in the
17 large wind turbine industry generally have comparable
18 capabilities. It's pretty much a uniform requirement, and
19 almost all the Americas, except for the contiguous 48 states
20 outside of the ERCOT and NERC region, some form of reactive
21 voltage regulation is expected and required of wind park.
22 Specifically, reactive voltage regulation is
23 required in Hawaii, Puerto Rico, the Canadian provinces of
24 Ontario, Manitoba and Brazil, all places where wind parks
25 comprise turbines, Siemens wind turbines are in operation or

1 in development.
2 Additionally, Siemens has examined
3 interconnection requirements in most of the Canadian
4 provinces and many Latin American countries, and we believe
5 that reactive voltage regulation by large wind parks is a
6 widespread requirement throughout the Americas outside of
7 the 48 contiguous states, outside of ERCOT.
8 Voltage support by wind parks is required by
9 ERCOT and was appealed by the Texas Public Utilities
10 Commission or to the Public Utilities Commission, so its
11 status is unclear presently. Reactive voltage regulation is
12 also a requirement of many countries in western Europe where
13 Siemens is a major vendor.
14 In the non-ERCOT NERC regions in the U.S., FERC
15 Order 661-A exempts wind parks from reactive power in the
16 absence of a need demonstrated by a site-specific study.
17 Consequently, most Siemens wind parks in these regions use
18 what Siemens describes as manual voltage regulation, whereby
19 the turbines regulate their own terminal voltages.
20 Although most of the parks operate in this mode,
21 some parks perform voltage regulation, even in the absence
22 of a site-specific study. This seems to be the standard
23 practice of plants owned by public utilities, for example.
24 Regardless, the overwhelming majority of the Siemens fleet
25 has the capability for voltage regulation at the transformer

interface with the transmission system.

In many cases, the capability of regulated voltage by regulated reactive power is available, with little or no expense or effort, but is not exercised. Some of the wind parks using our turbines have supplemental switch reactive resources, usually switch capacitors. Switch reactors are occasionally used as well.

To my knowledge, no parks using our turbines use supplemental dynamic reactive power sources like STATCOMs, SVCs or synchronous condensers, presumably because our turbines provide a substantial amount of dynamic reactive capability. But it would be possible to coordinate operation of these devices with a wind park voltage regulation system, particularly since Siemens sells STATCOM static bar compensators and synchronous generators, and has considerable expertise in the design and application of this equipment.

There are parks by other vendors that use supplemental dynamic voltage regulation equipment. Of course, Siemens takes no stand on whether reactive voltage regulation is being required for wind parks, but Siemens wants to point out that reactive voltage regulation is the industry norm in most parts of the Americas, and any position of reasonable requirements for voltage regulation would not substantially increase the cost of wind parks, but

1 would increase the complexity of their operations.
2 We would like to see wind parks treated
3 equitably, however. In some cases, reactive regulation
4 requirements were imposed on wind parks. Requirements were
5 imposed on the wind parks that were considerably more
6 onerous than those typically imposed on synchronous
7 generators.
8 For example, it is not unusual for an ISO to
9 stipulate .95 beats of lag over the full range of voltage
10 regulation on the transmission system, 95 to 105 percent
11 nominal. Synchronous generators can't do this. The
12 synchronous generator typically cannot provide any lagging
13 reactive capability of 105 percent voltage, nor any leading
14 reactive capability at 95 percent. These are the standard
15 terminal voltage limits of a synchronous generator.
16 Wind parks generally cannot match the reactive
17 capabilities of synchronous generators near nomianl voltage,
18 because they have greater impedance between them and the
19 system.
20 For example, typical wind park reactance, when
21 you go from the wind park terminals to the system, it's
22 usually a six percent reactance to the transformer, two to
23 five percent on the corrector system, to 15 percent on the
24 main park transformer. So we're talking about on the order
25 of 25 percent reactance. Typical for a synchronous

1 generator might be 15 percent.
2 So they can't matching the lagging capability,
3 but they generate, match or exceed the leading capability;
4 that is, the ability to depress the system voltage, because
5 of the fact that that reactance actually assists in the
6 leading mode. They don't have the concerns that synchronous
7 generators have for under excited operation, namely steady
8 state stability, impact heating and so forth.
9 A synchronous generator cannot generally provide
10 voltage support below about 90 percent or above about 108
11 percent because they're on terminal voltage limits. Wind
12 turbines have an operating voltage range of 90 percent to
13 110 percent. That's five percent on each side greater, so
14 they can generally accommodate transmission voltages in the
15 range of 85 percent to 115 percent, possibly more.
16 I'd like to point out that much of the reactive
17 power required for wind plant operation customarily is to
18 support reactive losses on the transmission system. This is
19 true regardless of whether reactive power is static or
20 dynamic. The cost of this reactive power could easily be
21 characterized as the cost of operating the transmission
22 system.
23 An alternative to providing reactive power at the
24 park level is to provide it at the transmission level. It
25 is by no means clear at the cost of supplying line losses,

1 that is reactive line losses, should be borne by the
2 generator only. There's a very legitimate argument that
3 sufficient reactive capability to operate the transmission
4 system should be included when the transmission line is
5 built, as part of the cost of doing business.
6 Requiring reactive power from the generation
7 resources increases the losses of the generating resources.
8 Reactive power can often be supplied with less real energy
9 loss directly on the transmission system. There are cases
10 of systems that have been operated successfully this way,
11 even here in the United States.
12 Finally, I'm aware of several large wind parks
13 that are required to install capacitor banks because of some
14 blanket requirement, often but not always the .95 lead to
15 lag. .95 lead to lag isn't a universal requirement. I know
16 of some places that require .9 lag, .95 lead; other places a
17 narrower range.
18 Often, when I am asked if the capacitor has
19 operated, the answer is negative. They were installed in
20 anticipation of a contingency that never occurred. But
21 there may be some cases where reactive power can be
22 justified, a blanket approach that is requiring the same of
23 all wind parks, may result in the waste of some reactive
24 capability. They can also have unintended consequences.
25 For example, I know of synchronous generators,

1 including nuclear units, that would not upgrade because real
2 power upgrades would result in their power factors exceeding
3 .95. In some cases, power upgrades may be available for
4 wind turbines that come with the sacrifice of reactive
5 capability. Thank you.
6 MS. CAIN: Thank you, Mr. Nelson. Kris Zadlo.
7 MR. ZADLO: Well thank you for letting me speak
8 again. I'd like to reiterate my comments from this morning,
9 that voltage support is local, and unlike real power, cannot
10 be transmitted long distances. I also would like to
11 emphasize that Order 661 and 661-A strikes a fair balance of
12 what's appropriate, between what's required for reliability
13 purposes and not to exceed unduly high costs of an
14 interconnection.
15 Given the physical characteristics of renewable
16 resources, installing additional reactive resources at these
17 facilities may not be the most efficient, from both a
18 technical and financial perspective. The industry's
19 traditional reliance on generation to provide reactive
20 support was driven by efficiencies.
21 It made sense for a nuclear generator that has
22 almost 100 percent capacity factor to provide reactive
23 support, or a baseload coal facility, or a thermal facility
24 located in a load pocket. It made sense for those resources
25 to provide that dynamic reactive capability the capacitors

1 don't necessarily provide.
2 Requiring wind generators to provide reactive
3 support is almost always an inefficient outcome resulting in
4 the unnecessary incurrence of additional costs. Wind
5 generators operate at levels, at various levels, and rarely
6 do they operate at full output. They're always somewhere in
7 between.
8 Installing incremental reactive resources is a
9 substantial additional burden. Dynamic reactive resources
10 are always the most expensive option. We should always
11 consider least cost solutions first, and they should be
12 investigated in the following order.
13 First, we should look at modification of existing
14 voltage schedules. Second, we should look at modifying
15 operating procedures, and finally, the installation of
16 static reactive devices. That will conclude my initial
17 comments.
18 MS. CAIN: Thank you. Robert Jenkins.
19 MR. JENKINS: Thank you. I won't reiterate too
20 much what I said this morning, because I know you're pressed
21 for time. As I did mention earlier this morning, the
22 genesis of the solar PV world was from the rooftops, where
23 we abided by IEEE 1547, which says thou shalt not provide
24 reactive power.
25 So the products that we had to choose from

1 vendors initially did not really have this feature
2 available. Things have changed quite a bit, especially
3 driven by some European standards. The vendors are now
4 starting to offer products, inverters that do have some
5 reactive capability, though it hasn't been -- it's not
6 uniform across vendors. Some of them will provide .93 lead
7 lag; some are .9 lead lag. It varies vendor by vendor.
8 It might be good if I just take a second to kind
9 of walk through a little bit of a PV plant, so you can get
10 appreciation of it, if you're not familiar with it. This
11 would be like the second slide in that deck. Okay. At
12 first, we just have the basic DC modules. Nothing fancy
13 here. There's a bunch of solar modules mounted on racks,
14 all connected together with DC wiring.
15 Next. Then you have, that just gets multiplied
16 through what's called combiner boxes. The various DC is
17 collected together. Go to the next. Then it goes into
18 inverters. Inverters are kind of the heart of the plant.
19 They convert the power from DC to AC. This is also one
20 source of reactive supply.
21 Go to the next. Then you have the balance of AC
22 system, that collects all these various inverters together,
23 takes it to the project station and then out the power grid.
24 Then the last one there is we also install a plant level
25 controller that allow all these various inverters, rather

1 than to work like a bunch of individual power plants, they
2 now can all work as a uniform or a single power plant.
3 Next slide, please. Okay. Talking really about
4 the controller. What the controller does is it senses the
5 voltage at wherever you would like to control. This is for
6 set point control, and it measures that voltage.
7 It calculates the deviation from the set point.
8 It then sends signals out to each inverter, or actually the
9 controller box the inverter, which talks to the inverter and
10 has the inverter adjust its power factor.
11 So the inverters are in a power factor control
12 mode, and the plant level controller functions as a type of
13 I'll call it AVR. That's not the exact precise term, to
14 achieve set point control. So what we have is a system that
15 I would call it dynamic, whatever that word means. It does
16 dynamically respond automatically to changing system
17 voltages. It readjusts the plant reactive output to achieve
18 this desired set point.
19 Now what we found sometimes, as I mentioned
20 earlier, that utilities have said well, we want faster
21 response. The response of this system can be in the order
22 of seconds, and they said well, we want one second response.
23 Really weren't given any justification. They said that's
24 just what we want, and one way to do that is through a droop
25 level control. A droop level control is where you don't

1 achieve a set point voltage, but it's all done inside the
2 inverters, can be done very fast.
3 But if you want a very fast response with a
4 voltage set control. Then we found ourselves having to
5 install STATCOM devices, and we've installed a couple of
6 those in order to meet the local utility's requirements.
7 Again, these requirements weren't supported by any
8 particular studies.
9 They were just the requirements, and in at least
10 one case, I think both cases they were kind of developed
11 because we were the first PV plant coming on their system,
12 and they really didn't have a requirement. So they had to
13 put something together quickly, and that's what it was. You
14 don't argue with your customers, so that's what we
15 installed.
16 So I go to the next slide, one of the things that
17 we have experienced is really some of these other parameters
18 I talked about. What is reactive supply, what should it
19 look like, and I believe it was discussed the first one,
20 that lower left-hand our first panelists discussed.
21 You know, do you really need to provide, I'll
22 call it a rectangle form of reactive supply over the
23 operating voltage range? If the voltage is already high, do
24 you need the ability to boost voltage? If with voltage is
25 already low, do you need the ability to reduce voltage?

1 That's difficult to do. Sometimes, that's a requirement.
2 But if you have more of the shape that I
3 describe, where you cut out the corners, where you're not
4 having to boost voltage when the voltage is already high and
5 when voltage is already low, then the system becomes much
6 easier design.
7 But that is a utility to utility requirement, a
8 utility requirement, so sometimes they allow this, sometimes
9 they don't. But it is a different treatment of asynchronous
10 generators than a synchronous generator. Also on the right
11 shows -- this was for one of our projects, the utility
12 requirements, the triangle, and then the green lines was
13 really showing our capability.
14 This was done with both inverters and some
15 supplemental capacitors installed at the project substation,
16 showing that we can meet this particular utility
17 requirement.
18 So as I mentioned, First Solar considers the
19 provision of reactive power, the original requirements, to
20 be part of good, you know, being a good grid citizen. More
21 and more equipment manufacturers are offering this
22 capability. Therefore, assembling a system with this
23 capability can be done at a modest additional cost.
24 However, you get into some other variations such
25 as high speed or capabilities that go beyond what's required

1 for a conventional generator, then we can start seeing the
2 cost rise and the complexity of the system increase, and
3 that's all. Thank you.
4 MS. CAIN: Thank you, Robert. Michael Jacobs.
5 MR. JACOBS: Thank you for the invitation from
6 the staff and the Commission, for putting this technical
7 conference together. My name is Michael Jacobs. I'm
8 Director of Market Policy and Regulatory Affairs for Xtreme
9 Power. I'm also vice chairman of the Electricity Storage
10 Association's Advocacy Council.
11 Xtreme Power is a manufacturer of turnkey energy
12 storage systems, based on proprietary battery technology.
13 We produce in the United States. Buyers of our systems
14 include utility companies, generators and industrial loads.
15 My comments briefly address the reactive power
16 characteristics of storage systems, and then the more subtle
17 questions of scope for designs, methods of obtaining
18 reactive power and how a needed analyses fall outside the
19 LGIP.
20 Storage systems have a few different basic
21 configurations. The new storage technologies, be they
22 chemical, batteries or flywheels, rely on a four quadrant
23 converter. This power electronics conversion between DC and
24 AC also allows for a full range of dynamic reactive power.
25 The speed of the controls and response on these

1 systems is faster than 50 milliseconds, and does not draw
2 energy from the storage. However, an important additional
3 difference available from storage systems is the capacity to
4 inject or absorb real power, which can stabilize voltage by
5 offsetting variable generation on a radial line, and also
6 reverse a voltage collapse or a spike.
7 The real and reactive power is delivered with
8 digital precision, unlike a conventional generator that will
9 have its operating parameters. Our 15 MVA system at the
10 Kahuku wind farm in Hawaii provides all of these services.
11 There are other storage technologies such as pump
12 storage hydro, which use a familiar rotating generator,
13 capable of providing reactive power, and compressed air
14 energy storage, which relies on a conventional gas turbine
15 with its familiar power factor capabilities.
16 Now the policy questions around Order 661-A, I
17 think, begin with defining the scope. Are we designing an
18 interconnecting facility, or are we adding to the much
19 larger transmission system? The decisions on reactive power
20 capability are clouded by confusion on this point. I see an
21 uneven treatment today that can be remedied.
22 The argument that prevailed in Order 661-A was
23 that transmission planning should determine needs and
24 procurements of reactive power, and a generator would not be
25 required to add reactive power capability unless a need was

1 present at the time of the interconnection.
2 In that approach, reactive power capability was
3 seen as a transmission upgrade and capital expended only
4 where need was found. This was a cleaner, more pure
5 treatment of generation competing against generation, and
6 treating transmission upgrades as a separate function made
7 with transmission equipment.
8 Perhaps this takes the separation of functions
9 too far, and causes the confusion that has brought us here
10 today. The alternative to include reactive sources
11 installed as part of non-transmission investment, or better,
12 revisiting the distinction between equipment for reliability
13 and equipment for economics, when both contribute to
14 reliability, certainly has merits.
15 We prefer transparency around reliability needs
16 such as reactive power, and equal treatment for all
17 solutions. When there is a need for reactive power or
18 transmission support more broadly, and the need is not
19 communicated through procurement processes, there is a
20 potential for misallocation of capital.
21 We hope that the several process reforms FERC has
22 begun will end the segregation of reliability needs from
23 energy investments. The treatment for generation for
24 reactive such as FACTs machines and transmission upgrades
25 are not equal when addressing a reactive power or voltage

1 support need.
2 As a supplier or industry of equipment that can
3 be a substitute for all three of these, we see that
4 inclusion in a study can differ, depending on the category
5 and the status. To bring this to a head, there is tension
6 between the competitive procurement for commodity energy and
7 a separated process for reliability mandates.
8 If the decision is to have a generator
9 requirement for valued reactive power, perhaps without
10 regard to need, then there should be a proper corollary. A
11 study and procurement process should provide an even basis
12 for the analysis and investment in any equipment that can
13 meet reliability needs.
14 In sum, if the full system can benefit from non-
15 transmission assets contributing to prospective reliability
16 needs, then there should be provisions to allow the same
17 solutions to be procured when reliability needs are being
18 funded. So I thank you for the opportunity to participate
19 and provide these comments today.
20 MS. CAIN: Thank you, Michael. Now Khaled Abdul-
21 Rahman.
22 MR. ABDUL-RAHMAN: Good afternoon. My name
23 Khaled Abdul-Rahman, and I'm the Director for Power System
24 Technology Developments at the California ISO, and in this
25 capacity, I'm responsible for the software developments and

1 techniques and approaches used during the market
2 application, as well as the engineering analysis
3 applications. I'm also involved in the renewable studies
4 and the various ISO technical tariff filings.
5 Above all that, I'm also very close to our
6 Operation Department. Those are my customers and I usually
7 provide them with the, with products that satisfy their
8 needs operationally. So I'm very familiar with the
9 operational challenges about integrating more renewables to
10 the grid and what is currently the status and what will be
11 the new challenges that the operators needs to have.
12 I'm attempting this on behalf of the ISO, because
13 my objective is actually to support the request of the
14 California ISO, to have the authority to apply uniform
15 reactive power requirements in terms of dynamic reactive
16 power control, voltage regulation and power factor control
17 requirements, to synchronous as well as asynchronous
18 resources, without the need for the time-consuming,
19 inefficient and inconclusive system impact studies.
20 At California, we have the 53 percent target by
21 the year 2020, as well known, and as was shown in the
22 morning by my colleague, Yi Zhang, you know, he showed the
23 diagram where we have in the queue about 17,000 megawatts
24 that is in our latest queue, and most of that is wind and
25 solar.

1 So we do -- we are talking about a real problem
2 that, you know, we will be facing, and we would like to
3 expedite and, as a matter of fact, enhance the process of
4 processing those in the queue and give them quick answers
5 and feedback, and above all, we want to give them some
6 certainty that will -- up front, in the beginning of the
7 process, rather than trying to give them some answers
8 towards the middle of the process or towards the end of the
9 process, or even after they go live.
10 After they go live and they think everything is
11 fine, and then we find out that no, there are some problems
12 that we did not consider. That will go to, you know, why
13 the -- maybe later, why we cannot capture all of those
14 issues up front.
15 So it is for this reason that the California ISO
16 is committed to facilitate the integration or the transition
17 to the cleaner future grid, and it is for this commitment
18 that we want to ensure that this integration of the
19 renewable is done in a secure and reliable way, so that we
20 don't put barriers into this process of integrating more and
21 more renewable integration.
22 So I think all of us agree that we need, you
23 know, nobody's questioning or trying to put barriers on the
24 wind or the solar to participate in the, or to integrate
25 them into the grid. It is the how that we are trying --

well actually, it is the safe path that we are trying to discuss here.

The ultimate goal of integrating the wind or any renewable resource is basically to fully utilize the plan's potential production. That should be our goal. I know people are talking about 50 percent, you know, 20, 50, 40 percent. Our goal should be, you know, why not we can -- whatever we can produce. If we can use it, you know, why not?

To succeed in this while keeping the power system secure and stable, it is extremely critical to establish this good coordination between how the wind and solar operate, as well as the operational need of the system itself. There are different types of reactive power resources that can be used, and I'm going to focus my discussion obviously on the reactive power side.

There are so many other things that is needed, but for the reactive power, there are different types. Reactive power, as my colleague basically discussed, synchronous resources and synchronous generation, transmission resources, as well as storage resources.

Synchronous resources are our, no doubt, the favorite reactive power type. Usually, they come from conventional thermal and hydrogen generation facilities. Synchronous condensers can provide the reactive power to

support the voltage of the grid, and they are capable of operating in power factor ranges, whether it's .9 or .95, you know, lead lag.

The issue here is I don't want to, you know, I think we -- most of the morning was more focused on the power factor capability, is it .95 or .5, or you know, maintaining the voltage. Or most of it is like more on the -- even the argument of the static or steady state requirements were being discussed.

What I want to focus on is those type of issues has already been, you know I think -- on most, so many occasions, there are so many studies. If you open any article in any magazine, describing the experiences of here in North America or abroad, you will find people are already beyond this point.

This point becomes like more of a moot point for other people, and I still see some kind of argument whether it is needed or not. The discussion right now is more on the dynamic reactive power capability, whether it is needed or not. Maybe that's, that's maybe more relevant.

Asynchronous resources include, you know, wind and PV or solar PV shunts, static VAR capacitor and STATCOM. Early designs of the wind plants consumed reactive power in proportion to the generated degree of power, and they tripped offline whenever the terminal voltage dropped due to

1 system disturbances.
2 So it is very difficult for any power system to
3 accommodate many plants of this type without reducing the
4 system reliability and degrading the performance. We have
5 so many examples that happens. You know, the last, I've
6 read, you know yesterday in an article in China in February
7 2011, one single plant failed, you know, caused a cascaded
8 failure or disconnection of 840 megawatts of wind power for
9 one single fault.
10 One month after that, in that same area, another
11 single fault in one plant caused a cascading loss of 1,000
12 megawatts. So I don't think anybody would like to see that
13 happening before we react, and before we start, you know,
14 changing our standards or requirements.
15 You know why that happened? I'm pretty sure they
16 did, you know, system impact studies. I'm pretty sure that
17 they tried to capture as much as they can, you know, the
18 different scenarios and situations. But why did it happen?
19 Because in operations, things will happen that cannot be
20 comprehended, or at least even accounted for.
21 There are certain situations, and when this hit,
22 you know, then we degrade the reliability of the grid. The
23 newer wind plants, I think my colleague has stated, they
24 have the capability to do that, to do dynamic, even reactive
25 power control, voltage control at the point of connection.

1 To the extent that reactive power wind generation
2 displaces the active power thermal generation, wind
3 generation needs to provide some of this reactive power that
4 is lost, due to the displacement of the active power, to
5 support the system and the voltage.
6 Those are kind of what we call, you know, grid-
7 friendly characteristics of these units, that we need to
8 work together in order to integrate more and more of this
9 kind of renewable resources.
10 These plants are also capable of active power
11 control at a given or at communicated set points. New wind
12 plants, solar and electric storage use, you know, I don't
13 want to go into detail, but they use the inverter to provide
14 reactive power capability.
15 For a PV solar, for example, I talked to a
16 developer of a solar, and I told him what is -- I mean we're
17 talking about reactive power and the cost and all of that.
18 I said what is the cost of getting a .9 lag and lead power
19 factor from a solar PV? The answer was shocking to me,
20 because he was saying that that's an increase of about ten
21 percent of the inverter cost.
22 Overall from a project cost point of view, it is
23 only about two percent of the total project cost. So we are
24 spending all of this. I think the question is not whether
25 it is economic or not economic or whether we are adding more

1 cost to the investor at the -- for, you know, for things
2 that may not be used.
3 It is actually the time that we are spending in
4 order to study things, and therefore that all of the ISO are
5 putting in those studies, to justify, you know, the two
6 percent increase in the total project cost.
7 Now I don't look at that as an increase in the
8 project cost, and if I am a developer actually, I will
9 appreciate reducing the uncertainty towards my investment at
10 the very early stage of this process, and to tell me that I
11 need to spend this amount of money, rather than to come in
12 the middle of the process and you help me with some amount
13 that you say you have to invest some more in order to get
14 connected, or even worse, after you're connected, you start,
15 you know, getting back with, you know, requirements that
16 says, you know, you need to put this in place.
17 The certainty of the investment, I think, at
18 least from a development point of view, seems to me
19 important. So it is a matter of timing here. Whether the
20 Commission is going to do, you know, you can offer us or
21 give us standard that at this time, or we're going to be,
22 you know, meeting again, maybe in a very short period of
23 time, if we believe that these renewables is going to be
24 integrating to the grid in large amounts.
25 I'm pretty sure that we will meet again to ask

1 the same questions, and at that time, we will be probably
2 giving stories about, you know, bad stories about what
3 happens because we don't have this requirement. Switchable
4 shunt capacitors or reactors are also used to provide
5 reactive power.
6 They are cheap in terms of initiation cost, but
7 they are discrete in nature because of the switch, you know,
8 switchable banks, and their response to the voltage problems
9 is the slowest among all of the reactive power controls,
10 since reactive power output of these devices is proportional
11 to the square of the terminal voltage.
12 The small drop in the voltage, when you need
13 actually to bring up that voltage, a small drop in the
14 voltage would reduce the capability of those reactive power
15 tremendously, because they're proportional to the square of
16 the voltage. Static VAR capacitor and static compensator
17 STATCOM, or power electronics-based devices, and they can
18 provide, like Michael said, absolutely terrific dynamic
19 reactive power control.
20 So why do we want to hold back on these excellent
21 resources of reactive power, and you know, try to justify
22 something that to most of us it seems that it is a must in
23 order to keep the safety and reliability of the grid. Now
24 it's not enough to say that normally the grid will operate
25 under these kind of, you know, under these kind of

1 situations, so you design or you plan based on that.
2 We have to cover all sort of worst conditions.
3 We have to cover all sorts of scenarios. The type of the
4 planning studies that we currently have does not and they
5 don't have the capability to find out or to discover all the
6 scenarios that can happen in operation.
7 Later on, you know, if we even think about active
8 power right now, there is a big discussion going on on the
9 requirement of the planning, in the planning phase, of how
10 much megawatts you need. The integration of renewable and
11 the instability that it gets into the grid, making that
12 process alone is very difficult.
13 When you think about reactive power, that is
14 multiple magnitude, you know, more difficult and it's hard
15 to find out all the scenarios. Monitor peak, off-peak, on-
16 peak, those are just approximations, by the way.
17 You will have to go to more probabilistic
18 approaches, stochastic approaches in order to try to find
19 the variability of these resources, and even that which is
20 not existing today, even that does not guarantee you that
21 you will cover all of the operational for what will happen
22 in real life.
23 I'm taking more of my time, I understand, but I'm
24 going to quickly finish. But I wanted to say that these
25 study, you know, what we are asking from these study or

1 impact study to enhancement is like eating soup with a fork.
2 Monitor, you know, it's like what do I do with it, you know?
3 Retrofitting is always an option, like when we
4 find problems later on, but the cost of retrofitting, as
5 many would agree with me, that it is very difficult, oh
6 sorry, it's very expensive later on, rather than planning
7 for it.
8 As far as other means of reactive power, it's
9 currently secured at California ISO. No payments for
10 nominal voltage support for participating generating units
11 while operating in the applicable power factor. Loss of
12 opportunity cost is paid to participating units when unit is
13 structured to provide additional voltage support by
14 operating outside applicable power factor range.
15 I would say that consistent with the above
16 comments, a uniform standard for reactive power control,
17 voltage regulation and power factor requirement has many
18 operational and planning benefits, to enable the integration
19 of more renewable energy into the grid.
20 We don't see it as a barrier. We see it as an
21 enabler for this technology to increase, and this will
22 prevent us from unnecessary project delays, avoid
23 inefficient operation of resources and ensure better
24 distribution of the reactive power throughout the grid.
25 Finally, the California ISO commends the

1 Commission for its recognition of the reactive power issue,
2 as it relates to asynchronous resources, and it's called for
3 this technical conference to review the various technical
4 opinions and practical experiences. Thank you.
5 MS. CAIN: Thank you, Khaled. Eric Laverty.
6 MR. LAVERTY: My throat got dry just from
7 listening.
8 (Laughter.)
9 Thank you for the opportunity to come back for
10 the afternoon panel. Having spoken this morning and being
11 on the RTO planning side, the comments at this panel will be
12 considerably briefer than they were this morning. However,
13 they are not zero. We do have a few here.
14 There are procedural impacts to the questions
15 asked about the technologies here, and just going through
16 those, you'd asked in the conference agenda about the
17 synchronous resources. We typically don't see them as a
18 problem with respect to the reactive power because of the
19 inherent capabilities they have, so long as the generator's
20 step-up transformer is appropriately sized.
21 If that's undersized and to get the full output,
22 you have to run pumps and fans. You're introducing motors
23 onto the transformer and some more reactive losses, and that
24 has been an issue once in a while. By creating the core
25 expectations Order 2003, that has somewhat abated. I think

it's mostly abated since then.

The other synchronous issue comes when there's upgrades to existing plants, maybe a retrofit of a replacement of a turbine, replacement of a pump, and they get more efficient. Well, that pushes out -- that pushes the mechanical power out, but you might get into an area on the generator capability where yeah, I can put more megawatts out, but you're cutting into the megavars, and we've had some interesting discussions with customers there.

Again, we've been able to resolve those cordially. But that has been interesting from a technical and a policy perspective. The newer asynchronous resources have also been less of a reactive power issue.

If you had a Type 3, Type 4 wind generator, those have pretty much been okay. There are, there are capabilities that they have. We put them in a model, run them, we've been all right.

There might be more of a regional issue, but that's because you've got a lot of megawatts going down skinny wires, as opposed to reactive capability local to the generator.

Energy storage requests. So far our footprint, those have mostly been a mechanical form of energy storage, coupled with a synchronous generator. Pump storage for hydro, compressed air, those type of technologies.

1 Only recently have we seen electrical storage
2 devices come in. Those conversations are still in the
3 exploratory stage. We haven't seen the official request
4 come in and get to the point where we start studying them,
5 to have a good feel as to what the technical challenges are
6 going to be there.
7 A concern we have with retrofitting the existing
8 generators with additional reactive capability is that
9 Section 2.1 of the Interconnection Procedures, both our
10 current tariff and the pro forma, requires a new request. A
11 change in operating characteristics such as that would fall
12 under the change of -- fall under that applicability
13 provision and require a new request.
14 So you're going to introduce time and uncertainty
15 to the project. Although you intuitively would not expect a
16 lot of upgrades to come from an additional reactive
17 capability, you're still introducing that time and
18 uncertainty into their project lifestyle, life cycle.
19 With respect to how the other devices such as
20 FACTs or power electronic devices are handled, we would
21 expect to see those come out of our reliability planning
22 process. It's not forbidden for them to come out of the
23 interconnection, but we would expect them to come out of the
24 reliability planning.
25 We could see voltage control issue or the need

1 for some voltage in our baseline reliability studies. It
2 might come out of a generator retirement study as well, and
3 these technologies would be part of the portfolio of answers
4 we have available to solve whatever the problem is.
5 It could be a simple capacitor bank may need a
6 FACTs device, you know. It depends on the nature of the
7 problem and what the solutions are, and what other benefits
8 are of having that device in place, and what the full
9 business case is for the upgrade.
10 Under some scenarios, maybe this could be part of
11 a multi-value project. I would expect it to be more on the
12 reliability side, but you know, we're open to that. If we
13 see the need and we see the business case for it, we'd be
14 open to this type of technology.
15 So in conclusion, we're open to updated
16 technology, and we look forward to a robust discussion
17 around this reactive power issue in total. Thank you.
18 MS. CAIN: Thank you, Eric. Dmitry Kosterev.
19 MR. KOSTEREV: Thank you for opportunity to
20 discuss the BPA experience with various wind generation
21 technologies. As I mentioned earlier today, we have about
22 4,500 megawatts of wind generation connected to the BPA
23 transmission system, 4,000 megawatt peak recorded by us in
24 the last month.
25 About 60 percent of the generators are Type 3 and

1 4, which is doubly-fed asynchronous generators and full
2 converter generators that Bob Nelson discussed earlier. So
3 we have a significant amount of induction generators, Type 1
4 and Type 2, and I think Khaled asked for the bad stories, so
5 I'm going to tell a couple, with a good ending, though.
6 So we still have, as I mentioned, many projects
7 which use induction generators, legacy projects. They were
8 connected six, seven years ago, before we developed the
9 requirements. At that time, this project didn't require the
10 STATCOM and the switch capacitors we use for reactive power
11 compensation.
12 Induction generators for every two megawatt of
13 active power production it consumes a megavar of reactive
14 power. So the shunt capacitors are used for the voltage
15 support and for the reactive power correction. So several
16 issues we had, undersize in the capacitors, controller
17 issues with capacitors not being switched, you know, when
18 they were supposed to.
19 We have the capacitor switching duty, because the
20 variations have been fairly high and you expect to switch
21 them more often, and then the usual capacitors on the
22 transmission system. We have discharge issues and then
23 capacitors not available for switching again.
24 So a couple of examples, specific examples. We
25 had a project which had Type 2 generators connected in 115

1 kV system, and we observed several events of slow voltage
2 oscillation, typically a 20 second period, maybe 40 second
3 period, and plus/minus five percent of voltage swings at the
4 point of interconnection, and accompanied by large reactive
5 power swings going roughly 40 megawatts for 150 megawatt
6 project is pretty significant.
7 It was significant that all those oscillations
8 occurred with all lines being in service. So again, that's
9 a condition when you're supposed to operate in a very stable
10 manner. So based on this experience, the plant was
11 curtailed to lower megawatt output when the operations were
12 more stable.
13 Subsequently, they added a couple of STATCOMs to
14 provide dynamic voltage control at the plant, and since then
15 we didn't see any oscillations. It operated pretty stable,
16 with all lines in service. However, the STATCOM wasn't
17 sized for the outage condition, and when outage occurred,
18 disturbance in the area, they experienced voltage decline,
19 which resulted in the tripping of the generators at the
20 site.
21 So the other example that we had is a project
22 which is midline connected. We had a 400 megawatt of
23 generation connected in the 230 kV line, and out of this 400
24 megawatt, 300 megawatt were induction generators Type 2
25 using shunt capacitors for the reactive control, and 100

1 megawatt was Type 3, but it was operating in power factor
2 mode.
3 So again, we saw a similar performance with some
4 voltage oscillations of, on one occasion with an outage
5 condition, and on the one condition we saw almost like a PV
6 curve nose. As you know, the power voltage curve is used to
7 measure the stability of the voltage stability of the
8 system, and it looks like from the SCADA data went right to
9 the nose of the PV curve. The slope was pretty much
10 vertical at the end.
11 This was on line service again, something we
12 didn't see in the studies. Later on, we found that the
13 capacitors didn't switch, and in some cases the reactive
14 losses in the collector system were not correctly modeled.
15 So since then, we added 200 megawatts of wind generation to
16 the same site.
17 How were we able to do that? Well, the new
18 plants were required to operate in voltage control in their
19 design according to the BPA requirements. So at one time
20 the 100 megawatt plant had the Type 2 generators, and it
21 includes STATCOMs, sized enough to contingency, and also the
22 shunt capacitors.
23 The other part was the Type 3 generators, which
24 had a reactive capability plus/minus .95 for the generator
25 side, and had the capacitors to compensate for reactive

1 losses. So our requirements, when we developed those
2 requirements, we were working with the manufacturers, trying
3 to understand what the capabilities of the equipment are at
4 the time, and make sure that we don't impose any additional
5 burden on the developers and the operators beyond what the
6 conventional equipment can provide.
7 So we had pretty satisfactory operations, you
8 know. Since the operators increased from 400 to 600
9 megawatt, we haven't seen any voltage stability problems
10 since. So again, the other issue that we have is the
11 coordination of reactive resources. When you have plants
12 which can control voltage and the ones which cannot, it's
13 very difficult to coordinate the reactive output.
14 But the issue we've seen is circulating vars and
15 I have projects which operate in voltage control. They're
16 producing vars, and then the projects which have shunt
17 capacitors, shunt capacitors don't switch because the other
18 projects are doing such a good job controlling the voltage.
19 So they're absorbing vars.
20 So we kind of have circulation of the vars in
21 which one is producing and the other absorbing, which is not
22 a very efficient operationality of the grid. So that's kind
23 of our operational experience with respect to different
24 technologies. Looking forward, we're doing studies with
25 projections up to 8,000 megawatt of wind in our system. So

1 it's double from where we are right now.
2 And assuming that we have the Type 3 machines or
3 Type 4 machines, which are designed equipment to our
4 requirements, we really didn't see any instability just in
5 the macrosense on our system. So that's kind of what we
6 have.
7 MS. CAIN: Thank you, Dmitry. Last, we have Jeff
8 Billo.
9 MR. BILLO: I guess the downside or maybe the
10 benefit, depending on how you look at it, for sitting at the
11 end of the table is that most of the comments that I would
12 have, have already been addressed. But I will make few
13 remarks in regards to our experience.
14 As I mentioned this morning, we have for a little
15 over eight years now, we've had a standard of .95 power
16 factor for all generating units connecting to our system,
17 and we're going on three years of having that standard
18 require dynamic support for that reactive power.
19 What we've seen is that of course synchronous
20 generation to meet that standard, you know, they're using
21 their excitation system, and that's kind of inherent in that
22 capability. The Type 1 and Type 2 wind generation plant,
23 which are the induction machines, to meet that standard they
24 have been installing additional devices at their site.
25 Whether that's capacitors and reactors, or in some cases,

1 SVCs or STATCOMs.
2 Since we've implemented the dynamic requirement,
3 most of the Type 1 and Type 2 requests have gone away, and
4 it's been almost exclusively Type 3 and Type 4 turbines
5 since 2009 that we've seen the requests for. Of course,
6 Type 3 turbines, the doubly-feed induction generators, have
7 the capability of providing that reactive support
8 dynamically.
9 I think approximately two-thirds of the wind
10 generation on our system is Type 3 machines, and Type 4
11 machines, the full conversion machines, they also have that
12 capability inverters. As far as solar and energy storage,
13 most of what we've seen, we haven't seen a lot of that yet.
14 We have some on our system. I think we have currently one
15 utility-scale solar PV on our system right now.
16 But most of the requests that we're seeing, the
17 inverter technology that they're proposing to use has that
18 reactive capability built in. This we sort of talked about
19 this morning. In ERCOT, we rely on the generators to come
20 to us with that standard requirement, and then we perform
21 reliability studies per the NERC TPL standards on an annual
22 basis to assess the system needs, beyond what the generators
23 provide and where we see fit, we'll propose static
24 capacitors, reactors, primarily and on some occasions, if we
25 see that need, we'll propose STATCOMs or SVCs as

1 appropriate. That concludes my remarks.
2 MS. CAIN: Great. Thank you, Jeff, and thank you
3 all of our panelists. As before lunch, we'll begin with
4 questions from staff. I have a couple of questions to start
5 off. The first, some of you have talked a little bit about
6 what it costs for wind or solar generators storage device
7 totally up to power capability.
8 Do you have a feeling for how much it costs as a
9 percentage of the overall project, and what is the
10 difference in cost if it's static capability or dynamic
11 capability?
12 MR. JENKINS: Robert Jenkins, First Solar. I'm
13 not sure we have it broken down quite in the same buckets,
14 but to get an idea, as I recall I had the diagram where you
15 had the DC system. They had inverters in the AC system.
16 Inverters in the AC system can account for 10 to 20 percent
17 of you total project cost, depending upon project size.
18 If you assume everything has to be upsized by ten
19 percent in order to provide reactive requirement, you get
20 close to the two percent number that Cal ISO had mentioned.
21 That's for a fairly basic system. If you want some of the
22 other things I discussed, the very fast response, where you
23 have to go to a STATCOM or some of these other types of
24 situations, the costs are going to be higher.
25 It's going to vary again, project by project.

1 They could be twice or more as high. A situation we have
2 not had yet, but is a potential, is also long gen-ties,
3 where the POI is quite far away, and then you're just not
4 physically able to provide that sort of reactor support from
5 the plant, to have it provide at the POI.
6 There, you're talking about building a whole
7 other station, and putting your reactive equipment there,
8 and the cost could escalate even higher at that point.
9 Again, that's going to be -- percentage-wise,
10 that's going to be difficult. It's going to be a very broad
11 range, because it's going to be a function of okay, what
12 size is your plant. I mean if you've got a 100 megawatt
13 plant or 200 megawatt plant or 300 megawatt, the big costs
14 are you're having to build a whole other station on your
15 line, so it's not going to vary too much.
16 So I don't really have a good number for that.
17 But let's just say for talking purposes, around the two
18 percent for a regular system. If we have to go with a fast
19 system, it could be twice as much more.
20 MS. CAIN: Thank you. Anyone else?
21 MR. ABDUL-RAHMAN: I can actually, just a quick
22 comment, Mary. I think one thing is to think about the cost
23 of how much it costs us to build this up front. But what I
24 wanted to, basically also to focus on, even from a developer
25 point of view, is what does it cost us to lose the business,

1 to lose the capability to deliver, the deliverability of our
2 megawatt, because of the lack of this capability?
3 Because that's money that we are losing, you
4 know, until we resolve that issue. When there is
5 availability on the grid, you know, physics flows will take
6 over, normal to what the politics would say. At the end,
7 availability is important and then the curtailment will be
8 happening.
9 That's a loss to the developer, that they need to
10 take into account, as part of the calculation of the cost.
11 You know, like anything else, what is my overall projection
12 of my, you know, profits and losses, and to calculate all of
13 that, in addition to the up front costs. That's the idea I
14 wanted to share.
15 MS. CAIN: Aaron?
16 MR. BLOOM: It would seem that another thing to
17 throw into that is what is the cost of providing reactive
18 power going forward. So you have the initial investment
19 cost, but what does it costing the resources every day, that
20 they have to back off of unity.
21 MR. NELSON: The dynamic reactive power certainly
22 is going to be an order of magnitude more expensive than the
23 switched reactive power, I believe. Also, another
24 consideration of dynamic reactive power is that those
25 dynamic reactive power device are normally inverter-based.

1 The inverters have an efficiency, you know, a real power
2 efficiency of around 98 percent.
3 So any time you generate additional reactive
4 current, that goes into additional loss of the device, and
5 that's a real power loss. Similarly, synchronous
6 condensers, the very best synchronous condenser might be 97
7 percent efficient. So any time you generate reactive power
8 with that, you're losing about three percent of the grid,
9 nominal capability of the device.
10 So those are real power losses, as opposed to say
11 for example switching capacitors on the transmission system,
12 transmission capacitors are a lot cheaper because of the
13 switches, but the capacitors themselves are relatively
14 inexpensive. You might be talking about an order of
15 magnitude of less cost and certainly an order of magnitude
16 of less loss. So those devices are on the order of 99.9
17 percent efficient.
18 MR. JALALI: Bob, can you explain, since you're
19 familiar with Type 3 and Type 4 wind units and also --
20 MR. NELSON: Not Type 3. We don't produce those.
21 MR. JALALI: Only Type 4.
22 MR. NELSON: We went directly from Type 1 to Type
23 4.
24 MR. JALALI: Okay. So I'm not sure if you -- but
25 if you are going to compare the cost of a solution to the

1 point of interconnection of the STATCOM solution cost,
2 versus the wind unit that has that feature incorporated
3 within, through the full interface converter, for providing
4 the same amount of dynamic megawatt capability, what numbers
5 are we talking about?
6 The reason I'm asking this question is my
7 thinking, and it could be incorrect, is that if the dynamic
8 reactor power is provided, through a Type 3 or Type 4, it
9 costs a lot less than if you say that unit's not going --
10 it's going to provide zero, and then I'm going to provide it
11 at point of interconnection. Can you clarify that in terms
12 of that is correct and that's --
13 MR. NELSON: First, I think they'd be reasonably
14 comparable costs, but I think the reason that the industry
15 moved away from the Type 1 and Type 2 designs was because of
16 the zero voltage ride-through requirement. It wasn't the
17 only reason, but it's very difficult for a Type 1 machine to
18 not go out of synchronism for a zero voltage incident.
19 They'll go out of step with the system, and there
20 are ways to overcome that, but it's almost impossible.
21 Also, gear boxes for those type machines got to be
22 prohibitively expensive. So you know, those technologies, I
23 think, are not even really feasible for use on transmission
24 system. It's not being sold, by the way.
25 MR. JALALI: I just want to just, in this

1 discussion, because Jeff made a comment. He said, and I
2 don't know if I correctly quoted him, as soon as we change a
3 requirement of .95 dynamic, the proportions of Type 1 type
4 units dropped dramatically, and they moved to Type 3 and
5 Type 4. If the cost was comparable, so if the only issue
6 was I put in outside solution versus inside solution, can
7 you explain what happened when you put that requirement of
8 .95 lead and lag?
9 You suddenly saw a shift from Type 1-Type 2 units
10 to Type 3 and Type 4. What do you think was the driving
11 factor for that?
12 MR. BILLO: And I'd like to agree with Bob, that
13 it was roughly the same time period that we implemented our
14 low voltage ride-through standard. So I think it's really a
15 combination of the dynamic requirement, as well as the local
16 contractor. I think at that point in time, roughly the 2009
17 time period is when we saw that Type 1 and Type 2 requests
18 were no longer coming in.
19 MR. NELSON: In theory, I guess, it should
20 actually cost a little less to have the full-sized STATCOM,
21 because you get some economies of scale from using a full-
22 sized STATCOM instead of using, you know, what we have in a
23 full converter design is individual STATCOMs at each of the
24 individual wind turbines.
25 So you're talking about some incremental capacity

1 at each of the wind turbines, versus the incremental
2 capacity in one large, lumped, perhaps plus or minus 50 MBS
3 stacking.
4 MR. JENKINS: One thing that might be pushing it
5 the other way is that when you -- when you put this in the
6 inverter, if we can do it with the inverter, say it's a ten
7 percent increase inverter capacity in the AC system.
8 But if you take the same amount of vars you have
9 to install with a ten percent increase, you have to install
10 a 50 percent increase, because you're installing a stand-
11 alone.
12 Say if you had 110 megawatts. Well, if you
13 wanted 50 megavars, you'd install 110 MVA (ph) facility.
14 But if you want 150 megavars, if you want 50 megavars
15 separated out, you've got 100 megawatts real power, and 50
16 megavars reactive power. So net capacity, you end up
17 installing more when you end up buying two separate devices,
18 as opposed to upsizing it just by ten percent in one device.
19 So it's really removing -- if we're providing it,
20 we'd rather provide it through the inverter. It provides us
21 some economies doing it that way, as opposed to providing
22 stand-alone devices. Now if we can use switching to shunts,
23 there might be some economies there. But rather than do
24 something like a STATCOM or an SVC, we'd much rather do it
25 within the inverter.

1 MS. CAIN: And Kris or Robert Nelson, can you
2 comment a little bit on winds, if it's more efficient to do
3 the reactive power within the Type 3 or 4 wind turbine or in
4 a separate device?
5 MR. ZADLO: It's probably, at the end of the day,
6 more efficient to do it with the Type 3-4 device, just
7 because from a controlling perspective, you have to switch
8 the capacitor bank on and off. So you get into this control
9 issues.
10 But what I do want to say is I think we're kind
11 of tip-toeing around the elephant here in the room, and the
12 real question is, you know, how do we pay for these
13 resources? To be clear, I mean we support reliability. We
14 understand if the system isn't reliable, we can't generate
15 and produce megawatts.
16 But there is a dichotomy here, in the sense that
17 well let's the Cal ISO or SBP. If the Cal ISO or SBP
18 required a transmission owner to install a capacitor bank,
19 transmission owner will receive full recovery on their
20 capital expenditure. If they require the generator to do
21 that, there's no mechanism for the generator to recoup their
22 costs.
23 Two to four to five percent increase doesn't
24 sound a lot, but it is a lot, because this is -- it's two
25 percent of a large number, so it's not insignificant. But

1 that two percent can be the difference between me receiving
2 a power purchase agreement and not receiving a power
3 purchase agreement.
4 So really the issue here is there's no mechanism
5 for me to recoup the reactive capability, or the additional
6 reactive capability that I may be required to install.
7 MS. CAIN: Thank you. This morning, we had some
8 discussion of how dynamic isn't necessarily a very clearly-
9 defined word when it comes to reactive power. Jeff in
10 ERCOT, when you put the dynamic requirement, how did you
11 define what equipment meets that requirement and what
12 doesn't?
13 MR. BILLO: Yeah, that's actually a really good
14 question. In the protocol requirement, there is some
15 language in there that if you -- and I don't recall exactly
16 how it's worded off the top of my head, but there is some
17 language that if you're uncertain, if the equipment that
18 you're planning to install can meet the dynamic requirement,
19 then you can come to ERCOT and we can analyze it and put it
20 into some stability analysis, and determine whether it's,
21 you know, quote-unquote "dynamic" or not.
22 Now to date, we've only had one request to do
23 that analysis, and then that plant went away. So we haven't
24 really had a chance to fully exercise that, that provision
25 that's in the protocols for that.

1 What we've seen is that most if not all of the
2 interconnection requests that we are getting, the Type 3,
3 Type 4 turbines or the PVC solar with the inverters, that
4 kind of inherently have that dynamic capability and we
5 haven't really seen an issue with that.
6 MR. LAVERTY: You know, in that vein, it's
7 probably easier to define static than it is dynamic on
8 these, because you can have switch shunts, but if there's a
9 control system that will move it, I had a developer tell me,
10 and this when I was a few jobs ago on MISO, but still in the
11 Interconnection Group, he said he had this ultra-fast
12 control scheme for his shunts.
13 I said oh, well what's the time? He goes I can
14 have those caps singing in a minute. I said oh, great. The
15 service lasts, you know, a fraction of a second here.
16 But okay, and you know, you can -- like I said,
17 you can model and show whether it's going to work or not,
18 but if it's going to require a manual intervention to switch
19 a discrete amount of reactive capability either way, then
20 that's just pretty easy to define as static.
21 MR. ZADLO: I was just going to say that I think
22 conventionally within the industry, if it's electronically
23 switched, it's dynamic. It's mechanically switched. You
24 can sort of switch or static, semi-static, whatever.
25 MR. JENKINS: I'll add that it's a gray line.

1 I've seen some proposals where you can use fast switch
2 mechanical capacitors, where you can close the mechanical
3 switch like a breaker. You can close it in a few cycles.
4 You've got the issue of opening or whatever.
5 But if you have an event that occurs, where you
6 have a deep voltage suppression and you need a fast
7 response, that is a possibility. So again, it's a very gray
8 line as to what falls into static versus dynamic to my mind.
9 MR. ABDUL-RAHMAN: I think for the dynamic, I
10 mean one requirement or one critical characteristic, it has
11 to be continuous. It has to be capable of providing, you
12 know, any value on a continuous range. A second thing, it
13 has to be fast. I will say this.
14 You know, like if we look at the capabilities of
15 the synchronous, so it's the AVR for example, that we use to
16 remedy the voltage collapse or the dampening effect of these
17 machines, you know, you could see how fast the response of
18 the synchronous resources.
19 Now we have seen characteristics of the, you
20 know, with the power electronics, using the product
21 technology. It's even faster than what we have for the
22 synchronous machine. So the capabilities that I think we
23 talked about, you know, some of these, that's what we call
24 dynamic.
25 Dynamic for us is I need a fast, continuous

1 response that will arrest, you know, basically these
2 disturbances and does not cascade the impact, or get me
3 closer to my voltage collapse point.
4 MR. BLOOM: I kind of wanted to touch back on a
5 comment from Kris earlier, and what some others have said.
6 If the costs of these FACTs or other STATCOMs are about the
7 same as providing the capability on a generator, and the
8 ability of these resources to respond to the problems you
9 have is about the same, and the only difference is that one
10 group of owners can put in the rate base and the other
11 can't.
12 It would seem like there would be an easy answer
13 to go with the people that can recover the costs easier.
14 Why isn't that the easy solution or the convenient solution?
15 Like why rely on generators, or why not just rely on
16 transmission? Why would you want to choose one thing over
17 the other?
18 MR. ABDUL-RAHMAN: Actually, we wanted also to
19 strike a balance, like what we talked in the morning. I
20 think there was some discussion that we're not asking any
21 sort of generator, whether it's synchronous or asynchronous,
22 to take all of the reactive power requirements and absorb
23 it.
24 We are just trying to ask for something
25 reasonable from the generation, whether they're synchronous

1 or asynchronous. And then like with I think others in the
2 morning said, we will look into the complement, because .95
3 or any requirement that we ask from as a standard or as a
4 uniform requirement, may not be all what we need.
5 And we're thinking, we're thinking of okay,
6 anything above that can go to the transmission, and we can
7 establish, you know, the reactive power sources there to
8 deal with this situation. But at least let's have some kind
9 of a common or uniform standard that provides us with this
10 fast response.
11 Usually, transmission is -- you know, the thing
12 is, this goes back -- okay. Can you figure out how much you
13 need? If I can figure out how much I need, and I'm very
14 sure that this is exactly what I need, I can put maybe a
15 device that can provide that. The problem is that there are
16 places where no matter how much you think up front about
17 different possibilities, you can not figure out the dynamics
18 that will happen in the real time.
19 It only takes one situation that you didn't cover
20 to bring the system down, and then after that, people will
21 not be talking about cost or this is just one case out of,
22 you know, thousand or million cases that you studied. It is
23 that case that failed that is going to be in question, and
24 why we didn't protect against.
25 So to me, you have to strike the balance. There

1 is no, you know. Some, that needs to come from the
2 generation. Now I think a real interesting question or
3 comment from Kris was who's going to pay for that? Well,
4 this is another question. This is like getting us into the
5 cost allocation. This even to me is that is an argument
6 against, is an argument that will support the uniform or
7 standard requirement.
8 Also, it supports the FERC's direction, if I
9 understand it correctly about, you know, the need for the
10 optimization of the voltage schedules at different location,
11 in order to better optimize the operation of the system.
12 Well, how are you going to do that voltage
13 schedules if you don't have these resources that's capable
14 of achieving that voltage schedule for you. So to me, this
15 is like a step in the forward direction, to have this
16 uniform standard, to take us to the next level if we
17 understand what FERC is trying to take us there.
18 There's another conference or there was a
19 conference about voltage and reactive power deferred, and I
20 see a lot of notices also from FERC about others. If you
21 are thinking in that direction, we need to think about how
22 do we get there then? That uniform or standard is in the
23 former direction or in the past direction of taking us to
24 that level. That's how we see it.
25 MR. LAVERTY: I get asked probably a couple of

1 times a year from developers, whether or not they would be
2 eligible for our, it's our Rate Schedule 2, reactive power
3 compensation, and because I was involved in it, and it was
4 hotly contested.
5 Then I went off and did something else for a few
6 years, came back and I had an expert that was handling it
7 and they're going to handle it. They knew she worked for
8 the Cal ISO, handed it off to his neighbor and she's pretty
9 good with it. I just give them my WEEDS (ph) number there.
10 And my answer has been if you meet the terms of
11 that, you can file a rate schedule and get it. I do not
12 know off the top of my head what those terms are, or what
13 the mechanics are of applying that. But that's how I've
14 answered that question from developers, is go take a look
15 here and you know, if you can do it, follow the procedures,
16 then that's where you are.
17 Then if they talk to her, I don't always hear
18 back from them. So we're missing a feedback loop there.
19 MS. CAIN: I have a couple of questions more
20 specifically to the design of wind and solar plants.
21 Especially for wind, once you have whatever requirements you
22 need to operate the wind farm amongst itself, and control
23 thing within the wind farm, and to get low voltage to drive
24 through, how much more requirement is it to get to the .95
25 leading and lagging power factor range?

1 MR. ZADLO: When you say .95 leading/lagging, at
2 the point of interconnect or --
3 MS. CAIN: Well, where you have -- where the
4 interconnection agreement says you have to have it.
5 MR. ZADLO: Okay.
6 MS. CAIN: And is that a different point for low
7 level to drive-through, where they measure that from the
8 power factor range?
9 MR. ZADLO: Typically, typically, what we found
10 is in the larger wind farms, we probably need a .05 power
11 factor just to maintain or kind of operate, just kind of
12 rule of thumb here, our own grid, okay, and then you lose
13 another .05 to go through the step-up transformer in a
14 reasonable T line. If you get a T line that's really long,
15 then you're going to have to do something else at the other
16 end.
17 So what we found is what we're purchasing is wind
18 facilities that generators are capable of producing .9
19 leading and lagging, in order to maintain unity at the point
20 of interconnect.
21 MR. NELSON: One problem that we have seen,
22 particularly with respect to the .95 lead to lag, as I
23 mentioned during my discussion, is that sometimes ISOs
24 require .95 lagging and 105 percent system voltage, and .95
25 leading, at 95 percent system voltage. It's a very

1 unreasonable requirement, something that can't be done by
2 synchronous generators, and yet it's been imposed on new
3 parks in various jurisdictions.
4 You know, generally speaking, you need to raise
5 your terminal voltage to provide lagging reactive
6 capability, and most converters and doubly-fed induction
7 generators lose capability as the terminal voltage goes up.
8 Similarly, you lose some leading capability as the voltage
9 goes down. That's not been as much of a problem.
10 Generally, the problem is the lagging capability
11 for high system voltage. So when you say how much extra do
12 you need, it could be installing 50 percent of the nominal
13 capability of the park in switch capacitors, just to provide
14 that capability, or something like that.
15 So, and a lot of that could be eliminated simply
16 by making the requirement a little more clear. .95 lead to
17 lag leaves a little bit to the ISO's imagination, in terms
18 of requiring it. They can impose a requirement like that,
19 and I'm not sure that it's always done out of malevolence.
20 Sometimes it's just done out of, I don't know what, maybe
21 ignorance. Maybe just because they're greedy. God only
22 knows.
23 But at any rate, that's been a problem. But
24 generally speaking, if you have a full converter or I think
25 this is true for a doubly-fed induction generator park as

1 well, you lose about 25 percent going from the wind farm or
2 wind turbine terminals out to the high side of the step-up
3 transformer, probably you won't lose too much more on the
4 transmission system, assuming a reasonable interconnection
5 distance.
6 But say you lose 30 percent. So if you're
7 putting out 50 percent at the wind turbine terminals, you
8 might be putting out 20 percent, which corresponds to the
9 .98 lagging. You might need to put in an additional, say,
10 13 percent or so in terms of switch reactive capability.
11 MS. CAIN: Thank you, and Robert Jenkins, First
12 Solar. How much additional reactive power capability would
13 be needed to meet the .95, besides what you need to control
14 voltages within the solar park?
15 MR. JENKINS: Okay. Our design often has, you
16 know, a blend of reactive coming from the inverter, as well
17 as some switchable shunts. Typically, the switchable shunts
18 are designed to offset the consumption within the collector
19 system and the step-up transformer. So you end up with,
20 let's see.
21 I'm trying to think of the math here, maybe an
22 additional 50 percent of reactive capability having to be
23 installed, just to manage the reactive requirements within
24 the plant. Then that leaves the dynamic range to manage the
25 issue at the point of interconnection.

1 MS. CAIN: And Mike Jacobs, when you buy an
2 inverter for a solar system, do you have different types of
3 inverters you can choose that have different amounts of
4 reactive power capability, or is it just a straightforward,
5 you have this many megawatts for your inverter?
6 MR. JACOBS: We do purchase on the market the
7 inverters at this point, and it's my understanding that to
8 do the bi-direction, we end up with four quadrants and the
9 full range. So we've never offered something other than the
10 full range reactive and real on the megawatt scale projects
11 inverters, yeah.
12 MS. CAIN: Thank you. We heard from Jeff Billo
13 that ERCOT has about two-thirds of its wind turbines right
14 now are Type 3. Do the rest of you have a sense for how
15 many turbines in different parts of the country? Are all
16 the new ones Type 3 and Type 4, or are we still seeing a mix
17 of different technologies?
18 MR. NELSON: Yeah. As far as I know, there are
19 no Type 1's or Type 2's being sold in the United States
20 anymore for transmission applications. I think it's been a
21 year or two since the last ones were being sold, in any
22 amount of volume.
23 I'm sure there are some replacement units going
24 on, but no new units being sold. They're all, to my
25 knowledge anyway, Type 3 and Type 4.

1 MR. KOSTEREV: Like in our system, you know, 60
2 percent of existing capacity Type 3 and 4, and moving
3 forward, all applications Type 3 and 4.
4 MR. LAVERTY: Yeah. I haven't analyzed the
5 numbers on that, but intuitively, anecdotally, I go with
6 Dmitry's assessment.
7 MR. NELSON: I think there still are some being
8 put in on the distribution system, but that's probably --.
9 MR. ABDUL-RAHMAN: Yeah. That's what I was going
10 to, my comment was is we have some very old wind turbines,
11 you know, because California it started like way back. So
12 some of those are still old ones all the new ones are Type 3
13 and 4.
14 MS. CAIN: Any other questions from staff?
15 (Off record comment.)
16 MS. CAIN: Is your mic on?
17 MR. MASOOD: On the wind farm, having reactive
18 support is not eating up the megawatt output. That's about
19 -- is that correct?
20 MR. NELSON: That's correct.
21 MR. MASOOD: Okay.
22 MR. NELSON: To a large degree. I mean to the
23 extent that you're providing additional reactive current,
24 there's some additional losses in the transformer that
25 you're not coming out of the wind turbine --. So it's no

1 megawatts coming out of the wind turbines --.
2 However, there's additional reactive current
3 being carried in the transformer, the turbine transformer --
4 , the park transformer transmission lines --.
5 MR. MASOOD: Okay, thank you.
6 MS. CAIN: Going back to -- oh yeah. Kevin.
7 MR. KELLY (off mic) I'll do this without a mic
8 if I could.
9 COURT REPORTER: Identify yourself, please.
10 MR. KELLY: When you asked your first question --
11
12 MS. CAIN: Can you identify yourself too?
13 MR. KELLY: Just Kevin Kelly with FERC staff.
14 Mary, when you asked your first question about the
15 percentage cost increase, I noticed that Kris Zadlo raised
16 his hand to answer, but then the conversation swung to the
17 far end, and I was curious about what he was going to say.
18 MS. CAIN: Please, go ahead and share with us.
19 MR. ZADLO: I think I forgot, but well I think
20 the point that I wanted to make was that two percent of a
21 large number is not insignificant, and it could be the
22 difference of success and failure. The other thing to keep
23 in mind, and as a transmission planner I get it.
24 Dynamic vars, it's the gold standard. It's the
25 difference between a plasma TV and your old black and white

1 tube TV. I mean everybody, if I'm running the grid, I want
2 dynamic vars.
3 Again, we have to keep in mind the
4 characteristics of a wind farm, okay. You've got a wind
5 farm that's located remotely. You've got these strings that
6 can be 7 to 10 miles long, and you've got a turbine at the
7 end of the string that's got a little pad mount transformer,
8 and then it gets stepped up to a subtransmission voltage of
9 34-5, and it has to travel eight to ten miles to a collector
10 substation, and then you have to travel another ten miles to
11 the point of interconnection.
12 It may be physically impossible to provide those
13 dynamic vars at the point of interconnection, just because
14 of the characteristics of the wind facility, and that's
15 something we need to keep in mind here.
16 MR. KELLY: So you can have -- so we've got all
17 these Type 3 and we've got these Type 4 generators, and they
18 can control their reactive power requirements within their
19 small collector region, but it's just -- you know, or just
20 to get to the next turbine or wherever they need to connect.
21 But they can't get it all the way to the point of
22 interconnection. That's what you're trying to say, right?
23 MR. ZADLO: It depends.
24 MR. KELLY: For the long, if they're strung out?
25 MR. ZADLO: Right, right. But just again

1 remember, vars, you can't push vars. Vars is local.
2 MR. KELLY: So basically this means in a park
3 with that type of configuration, where it's got a long
4 distance between turbines or to the point of
5 interconnection, then you need to add some other equipment
6 at the point of interconnection, in order to get the results
7 people are looking for?
8 MR. ZADLO: Right.
9 MR. KELLY: Okay.
10 MS. CAIN: Dmitry had a comment, and then Robert.
11 MR. KOSTEREV: I think our operational experience
12 suggests something different, you know. We have a project
13 which is 100 megawatt project. It has some shunt capacitors
14 as a part of the project, but it can push out as high as 60
15 megavars to the high side of the transformer. So if the
16 collector system is designed appropriately, they certainly
17 can, and they have excellent performance.
18 MR. JENKINS: Yeah, pretty much the same point.
19 You know, when you generate reactive power into the
20 transmission system, as I said, there are losses that take
21 place, reactive losses that take place in the turbine
22 transformer, usually around six percent. Collector system,
23 you know, varies, but two percent to five percent typical.
24 Step-up transformer, maybe 15 percent. Another couple of
25 percent in the transmission system.

1 That all comes out of the inductive side. So if
2 you're generating say for example, to put out 60 megavars
3 from the park and 100 megawatt park, from the turbines 100
4 megawatt park, you might lose 25 of those megavars to the
5 transmission system. That can be offset by putting some,
6 say, switch capacitors in the wind park.
7 So you can deliver the full dynamic -- the full
8 dynamic range doesn't change. It just has shifted over by
9 the dynamic process in the system. So you can compensate
10 for that loss.
11 MS. CAIN: And is there a significant cost
12 associated with that?
13 MR. JENKINS: There is the cost of installing
14 these switch capacitors.
15 MS. CAIN: Okay.
16 MR. NELSON: There's also some loss in real
17 power, because there's some losses that take place in the
18 transformers, and usually a real good rule of thumb, I found
19 anyway, is somewhere between two and three percent of the
20 wind park, of the aggregate wind turbine output doesn't make
21 it to the transmission system, and similarly, you know, you
22 can scale off of that the additional loss resulting from
23 increasing reactive current generation.
24 MS. CAIN: Pat, did you have a question?
25 MS. DALTON: I think Mr. Nelson might have just

1 answered it. I wanted to ask Mr. Abdul-Rahman if you had
2 suggestions on if you don't look at it on a case-by-case
3 basis, and these wind turbines are all, are not necessarily,
4 even if they're all Type 3 and Type 4, they all have their
5 own specific issues, how would you determine what the
6 uniform requirements are?
7 MR. ABDUL-RAHMAN: So this is what we actually,
8 in our early filing, that we were not approved by FERC, and
9 that's we have this hearing here. We specified in that
10 filing actually language of what are we asking, basically in
11 terms of the uniform application of the standard that we're
12 asking every kind of generator.
13 You know, even in that filing, we didn't go all
14 the way to the dynamic reactive power, in the sense that we
15 said for the dynamic reactive power, we are ready to work
16 and do the study for that, for that case. But for the
17 static and the control of the reactive power in terms of .95
18 power factor, those are to us is a minimum kind of a
19 requirement that we need at the point of the
20 interconnection.
21 So those ones, we say in the state of our
22 spending our time, proving again and again the majority of
23 the cases, and we're not talking about like, you know, half
24 of the cases need and doesn't have.
25 Based on the actual studies that we have done so

1 far, the majority of our cases require the reactive power.
2 Even the ones that we initially think they don't, at later
3 stages or in later clusters, we found that they need.
4 The majority of them need it. So instead of us
5 spending all of our effort, and there was a question in the
6 morning about how much effort we're spending, we have a full
7 staff, you know, two-three people, four people that just
8 doing this.
9 Instead of them spending that on something that
10 is obvious, why don't we spend our time on studying, you
11 know, more complicated and more advanced things like the
12 dynamic and like, you know, the focus on our point of
13 interconnection, and make it very certain, and make the
14 requirement solid.
15 For anyone who wants to come in, he knows exactly
16 how much money he wants to spend. He knows exactly how much
17 money he is investing. He knows exactly what is the
18 business case for him to, you know, for 10-20 years,
19 depending on the life of that project.
20 Instead of guessing, I don't need it now but I
21 need it later. Or I may not need it, you know, I may need
22 it even just before I go online. Those are, to us are kind
23 of barriers. I look at them as barriers to more renewables,
24 rather than helping the renewables.
25 MS. DALTON: But I thought the problem was that

1 they didn't know, the study was to help them determine?
2 MR. ABDUL-RAHMAN: That's the point. I think
3 what we see in this study is -- you see, this the nature of
4 those studies. We tend to think that this study has the
5 answer. It doesn't have the answer. It is just a very
6 approximate way, based on our old techniques of how we do
7 our planning.
8 But I mean those studies are, they're running
9 power flow, they're running, you know, based on certain
10 scenarios. The tool itself, power flows, is therefore so
11 many years, right? But what do you put into it? What is
12 the imputator to that tool? It is an assumption, and how
13 good is the output is based on how good your assumption.
14 MS. DALTON: Then what is it that comes out later
15 on, that indicates the need for reactive power, that you
16 don't see in the study?
17 MR. ABDUL-RAHMAN: Yeah. So later on, some of
18 the -- some early requests that used to be there are not
19 there, or some early requests we didn't have. They came
20 back, and then -- or are added to the queue. So and even an
21 area that you think that there wasn't a need, but then later
22 on you find out okay, now I have more, and there is a need
23 now.
24 We see it as, you know, even if we could -- if we
25 say for -- if I'm a developer, and I get the study from the

1 ISO that says you don't need to have that capability, is
2 this something that I will -- I don't think I will be, you
3 know, like relaxed to say oh, it's good. I don't need to
4 spend that money.
5 Because I will probably need to spend it if more
6 people came in that area, and then all of a sudden that
7 reactive power requirement is imposed on me.
8 The other thing is fairness. You know, like even
9 if we say that whatever we approved we don't, you know,
10 change, that becomes an issue of fairness and who comes
11 first and who comes last. You know, you get into those type
12 of issues unnecessary, instead of focusing on the real
13 issues.
14 MR. BAK: I have a follow-up question with that.
15 You said that the majority of the studies you do result in
16 wind turbine systems needing to have reactive power. Do you
17 have a sense of what that percentage is?
18 MR. ABDUL-RAHMAN: (off mic) I think my
19 colleague in the morning, he gave some numbers. I think out
20 of like 90 or 70 projects, there was 13 that did not meet
21 the rest of them. Yeah, he gave some numbers. I can't
22 remember them exactly, but that's about those numbers.
23 MR. JALALI: I've got a follow-up question also.
24 If somebody comes today, and you find out that there's a
25 need for reactive support, but you said five years later,

1 there's a need, he's not going to pay for that, right?
2 MR. ABDUL-RAHMAN: We're going to get into these
3 type of issues. Who is going to come later? If we go with
4 this approach, then who's going to come later is going to
5 have to put a lot of reactive power support, rather than now
6 having to distribute that amount for, you know, in small
7 chunks.
8 Now that is a barrier now to the person who's
9 going to come later, because now he has to spend a lot of
10 money to be able to connect to the grid. That's how I see
11 it. I see that it is a barrier. It is not helping. Of
12 course, if you ask me, you need to spend money. Of course I
13 don't like that.
14 But when I look at it overall, I think it should
15 start, you know, making some sense that yeah, I can spend
16 some money up front, but this is providing me with these
17 capabilities, that I can participate in operation more
18 effectively. Because there's no, even if I say okay, you
19 connect 100 megawatts, right, capacity, but you cannot
20 operate that 100 megawatts. When does it do you good to
21 operate, you know, at some period and then at other periods
22 you get kicked out?
23 That doesn't help. But instead of that, you
24 know, you need to calculate. This is a business case. You
25 need to calculate how much, what is the risk of not

1 operating? What is the risk of the added cost of
2 investment, and what is the cost-benefit?
3 MR. JALALI: Another answer is like in operation,
4 there are so many scenarios. You're going to study all the
5 scenarios. So maybe next month or next year, something may
6 show up which was not studied.
7 MR. ABDUL-RAHMAN: Yeah, I have a comment
8 specifically for this, is even if we don't have the wind or
9 the variation of the wind, people who were going into the
10 online, you know, even before the voltage stability, online
11 voltage stability, this dynamic stability. Those are
12 things, why people, you know, those are planning
13 applications.
14 But we see that an industry is moving in the
15 direction of putting those planning functions into the
16 online meanings, running it on the real time system.
17 Because they don't trust that whatever the scenarios that we
18 have in the planning, no matter how good they are.
19 I mean I'm not saying that -- I'm not making
20 anything against the planning per se. It is just no matter
21 how much you perfect your study, you cannot satisfy or you
22 cannot comprehend all of these scenarios.
23 That's why people are running these voltage - -
24 Right now, most of the ISOs, most of the companies,
25 transmission owners, they're trying to run it, evaluate the

1 real time situation because of this.
2 So now impose or add the variability of the
3 renewables into the picture. How can you, you know, figure
4 out what scenario to use? Plus add to that the changes in
5 the topology of the network, and the different megawatt
6 levels.
7 It is very -- for voltage, it is important to
8 know where is, what is the state of your -- it's different
9 than the megawatt, like when you do our studies related to
10 the megawatt itself. The voltage, you have to know where is
11 your operating point.
12 It's not enough what is the capacity of this
13 generator or that; it's what is the operating point that
14 you're going to be operating at? What is the state of the
15 system? That is difficult. I mean nobody has an answer, to
16 figure what to do in these impact studies.
17 MS. CAIN: Kris Zadlo.
18 MR. ZADLO: I recognize, and my view is every
19 study is incorrect. It's just a snapshot in time. But when
20 we go through the interconnection process, we don't expect
21 the studies to quantify every scenario out there. But we do
22 expect them to quantify the majority of scenarios that we
23 may or may not -- that we may face in the future.
24 So to the extent, and we also expect that once we
25 get through the system impact study phase, what's been

1 identified for interconnection would essentially allow us
2 for reliable operation. To the extent that once you go
3 online and there's significant curtailments or significant
4 issues, then to me that says that the study's been performed
5 incorrectly. Yes, there will be times where they'll be --
6 the system will be busted up or there will be strange
7 situations where you're going to be curtailed. But this
8 should not be something that's happening on a routine
9 occurrence.
10 MS. CAIN: Thanks.
11 MR. BLOOM: It seems like one example that we hear
12 about is that oh, we run into a voltage problem and all of
13 the sudden we have a cascading blackout, or some other
14 cascading problem. That seems to be probably an extreme
15 example of a problem with a shortage of reactive power.
16 How are the day-to-day operations impacted by,
17 small local issues? Does it result in just a lot of uplift
18 to the market? How does it manifest itself in daily or, you
19 know, monthly type of problems?
20 (Off record comment.)
21 MR. BLOOM: Particularly in the R2. I mean it
22 seems like are they just incurring uplift costs in order to
23 provide this voltage support?
24 MR. ABDUL-RAHMAN: Yes. I'm giving Dmitry, you
25 know, some, a minute to think. So right now at California

1 ISO, as I said, we have this reliability must-run units,
2 which to provide that voltage support, and those are
3 identified in the local areas.
4 So now for these local areas, you have to have
5 that voltage. You know, the market, currently the markets,
6 they don't have the capability or they only see, and this is
7 another point, they only see this reactive capability or any
8 requirement to commit certain units from a reactive point of
9 view, as a constraint into that application.
10 We have normal ground constraints, which tells us
11 how much, for example, needed generation or import to that
12 certain area. That's a new ground constraint that we have
13 in this application, in order to commit units, you know,
14 from a market point of view.
15 But when the constraint is actually voltage
16 constraint, or if we cannot formulate it in terms of a
17 normal ground that the market can understand, we have to
18 commit them manually, basically must-run, and We have long-
19 term contract with those must-run units. If, and as I said,
20 anybody, all other units, they operate with a certain range
21 that we don't pay within that range.
22 But and if we ask them, if we have to lower their
23 megawatts in order to move, for them to provide a certain
24 reactive power capability outside that normal range, we pay
25 for the lost opportunity cost for them to provide the active

1 power, because we --. That's the mechanism currently we
2 have for the --
3 MR. BILLO: The operators are going to do
4 whatever they need to do to keep the system reliable. An
5 example, we have a part of our system where it's served by
6 two 345 kV lines. One of the 345 kV lines was out for
7 construction contingency loss. The next one would cause a
8 slow voltage collapse, that type phenomena.
9 Our operators put together a mitigation plan, in
10 which we shed a significant amount of megawatts of load,
11 should that contingency occur. In addition, they asked the
12 local transmission utility to implement an under-voltage
13 load shed scheme, in case that contingency were to occur in
14 the future. With the other line out of service, then they
15 would shed load.
16 So I mean they'll do whatever it takes to keep
17 the system going, even if it's situations where we didn't
18 contemplate it in the planning.
19 MR. BLOOM: Right, and I understand that. What
20 I'm trying to figure out is are there costs associated with
21 that? How do those costs get applied to the market and you
22 know, how can we, as the Commission learn about those costs
23 or better understand those costs, to get a bearing on what
24 the problem is here?
25 MR. BILLO: Yeah. I mean it could be a cost

1 issue, where we're asking generators to maybe back down on
2 their megawatts, to supply more megavars. But you know, we
3 don't always quantify the cost of reliability as an impact
4 on the system to where, you know, if they need to do
5 something or if they have to shed load, we may not quantify
6 that cost, but it is a real issue.
7 MR. LAVERTY: Some of our load-serving entities
8 have what they call take or pay contracts. When power, where
9 if there's a transmission curtailment, transmission-related
10 curtailment, they still pay the generator. So their load is
11 paying for that.
12 When you look in the planning horizon, this
13 really comes down to which NERC standard gets tripped under
14 what study scenario, you know? Is it one that applies to
15 the generator owner that are going into retrofitting? So if
16 it applies on the transmission system, there's going to be a
17 voltage-related upgrade involved.
18 So these, they will show up in one of two
19 horizons, and you know. It just goes -- so if it's not paid
20 for at the interconnection, it's going to get paid for at
21 some point in the future.
22 MR. KOSTEREV: Maybe comment on our system. We
23 don't have the market, but we have a reactive reserve
24 monitor in our system, because the generators provide the
25 critical voltage support for California-Oregon intertie,

1 Pacific HBDC intertie.
2 So we have a requirement to have certain amount
3 of dynamic active reserves in the generators in the lower
4 Columbia, and should we get below that level, we would call
5 the transfers on the interties, to maintain the reliability
6 of the system.
7 So that's why I want -- when replacing the
8 conventional generators with the wind generation, we need to
9 have the same capabilities, to provide a dynamic reactive
10 support so we can export the power to conform them.
11 MS. CAIN: Are there any other questions from
12 staff?
13 MR. JALALI: Yeah. I just want to kind of a
14 little bit more clarification on, and I'll ask this question
15 from Kris, Type 3 and Type 4 wind units. Do they have
16 comparable dynamic power, providing dynamic power to
17 synchronous machines, and the difference is that it's just
18 there is this long lead time, that there needs to be fixed
19 shunt capacitors be provided to compensate for that portion.
20 And in that case, if we are moving to the world
21 that Type 3 and Type 4 are going to dominate, then are these
22 comparable or what's the difference then that we're talking
23 about?
24 MR. ZADLO: Yeah. Actually, Sassan, I think
25 really the only difference is the long T line, and when you

1 compare the Type 4 versus a synchronous machine, and maybe
2 Robert will chime in, I actually think that a Type 4 machine
3 provides better reactive power. Just it can respond
4 quicker, it has a larger range, and you know, depending on
5 the power factor, the power controls, it could provide the
6 full range at lower output levels than a synchronous machine
7 actually could.
8 So and you have a wider range of operational
9 capability. So I think it's actually superior to a
10 synchronous machine.
11 MR. JALALI: Okay. So in that case, requiring on
12 one a .95 power factor without any study, and on a different
13 type requiring, you know, per se, how do you see this whole
14 thing? I mean right now the way it's done is the other ones
15 are going to provide it, without a study of synchronous
16 machines. But those ones are, you're saying they're
17 comparable and even superior. But they need to be studied
18 on a case-by-case basis. If they are comparable, then
19 what's the --
20 MR. ZADLO: Well, okay. Technology-wise, maybe
21 they're comparable if not better. But then you have to step
22 back and look at where are they located on the grid? If I'm
23 a wind generator, okay, in a remote part of the grid, and
24 the generation that I'm displacing is a local unit that's
25 local in a major metropolitan area, it doesn't matter how

1 much reactive power I can generate.
2 I will not be able to provide the reactive
3 support that that generator that I'm displacing has provided
4 in the past. You know, Eric mentioned in the morning about
5 how they perform studies. Generators in Iowa cannot provide
6 reactive support for generators in Indiana. It just doesn't
7 work that way.
8 So I think that's the issue here. It's what
9 reactive. It's not the comparability of how they operate;
10 it's the location on the grid, and what -- every var on the
11 grid is not the same. The megawatt is the same, but not the
12 vars.
13 MR. JALALI: Okay. But I thought there was also
14 a limit on the Type 3, Type 4. When you get .95, you're not
15 going to go and say make it .85 or .8. So there is a
16 certain --
17 MR. ZADLO: Right, right. I don't think you can
18 go beyond .9, unless Siemens' got an issue. I think it's .9
19 and then you put in capacitor banks to make up the
20 difference.
21 MR. JALALI: All right, thanks.
22 MR. NELSON: Yeah. As with anything, there's a
23 trade-off between real power and reactive power. We operate
24 off of a curve, and in fact, you know, the converters are
25 voltage- and current-limited. That is one specific

1 difference of the converter type technology versus the
2 generator-type technology. Generators are power-limited.
3 The reactive capability curve is the same,
4 irrespective of whether it's 105 percent terminal voltage or
5 95 percent, one curve. If you look at the reactive
6 capability curve for a converter, you'll see that it's got a
7 different reactive capability, depending on the terminal
8 voltage, and usually they're optimized to put out their
9 maximum lagging capability at nominal voltage, and it
10 decreases as you go up or down in voltage from that voltage.
11 Leading capability is always current-limited. So
12 it's always going to be increasing with increasing terminal
13 voltage. So there is some capability, there's some
14 similarity in the capabilities, but also the same
15 differences as well. One important difference is that the
16 wind turbines have an operating voltage range of 90 percent
17 to 110 percent, versus that of a sequence generator, which
18 is by standard 95 to 105 percent.
19 So a synchronous generator can't provide any
20 lagging reactive capability at 105 percent terminal voltage,
21 whereas a wind turbine can provide some. Maybe it's reduced
22 from the nominal capability, but they still can provide
23 some. What this means is that they can control a larger
24 voltage on the transmission system typically.
25 But when you compare them one for one, if you

1 consider 25 percent reactance between the wind turbine
2 terminals and the system, you know, if you just think about
3 what a -- you know, just in power terms, a generator with a
4 reactive power output of .9 lagging is putting out 1 plus
5 J.5 roughly.
6 Then as it goes through the system, it's going to
7 lose roughly 25 percent of its reactive capability. So what
8 puts out through the transmission system is 1 plus J.25,
9 which corresponds to something like -- I mean a calculator
10 will do it precisely, but something like .96 or .97.
11 The synchronous generator, on the other hand,
12 only loses about 15 percent. So it goes from 1 plus J.5 to
13 1 plus J.35, .95. That's pretty much, I think, where the
14 number came from.
15 I'm not sure, but I'm not sure that an awful lot
16 more thought went into it than that. But that typical
17 specification was .9 power factor lagging at the terminal
18 corresponds to .95 at the high side of the step-up
19 transformer.
20 And so, you know, you've got some distinct
21 differences there. So applying the same rules, saying okay,
22 .95 at the point of interconnection is a level playing
23 field, it's not quite correct, because the wind power has
24 considerably more reactance. But then again, it can be
25 compensated by installing some switch capacitors or

1 something like this.
2 MS. CAIN: Any last questions from staff? No.
3 We are going to start losing a few panelists who have
4 flights to catch, but we have a few minutes. Are there any
5 questions from the audience, specifically on the topics
6 we've discussed today, about the system studies or the
7 capability of the different types of resources?
8 If anyone in the audience has a question, raise
9 your hand. If not, I am seeing no questions in the
10 audience. I guess we'll wrap up today's conference.
11 We appreciate all of the questions and comments
12 that you've shared today, and we've learned a lot about
13 reactive power and how you study it and the system impact
14 studies, and what all the different types of resources are
15 and how some of these technologies are changing.
16 We will be accepting written comments after this
17 technical conference for 30 days, in Docket 80-12-10. So if
18 you have any comments to clarify something that was said
19 today, or to give more detail, we would appreciate those,
20 and we're specifically interested in comments about the
21 system impact study, what evidence could be submitted for
22 Order 661, 661-A, and also about the different types of
23 technologies.
24 Thank you all for coming. This concludes today's
25 technical conference.

1 (Whereupon, at 3:12 p.m., the meeting was
2 adjourned.)
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