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In the matter of :

REVIEW OF GENERATOR : Docket No RM16-12-000

INTERCONNECTION AGREEMENTS :

AND PROCEDURES :

AMERICAN WIND ENERGY ASSOCIATION:

The technical conference in the above-entitled matter was convened at 9:00 a.m., pursuant to Commission notice and held before:

CHAIRMAN NORMAN BAY
COMMISSIONER CHERYL LaFLEUR
COMMISSIONER COLETTE HONORABLE
COMMISSIONER TONY CLARK

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3 JOMO RICHARDSON
4 THANH LUONG
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15 ANUJ KAPADIA
16 JOSEPH NAUMANN
17 KAITLIN JOHNSON
18 KATHLEEN RATCLIFF
19 FRANKLIN JACKSON
20 JORGE MANCAYO
21 LESLIE KERR
22 MARK BYRD
23
24
25

1 PRESENTERS:

2

3 PANEL 1:

4 Tim Aliff, MISO

5 David Gabbard, PG&E

6 Dean Gosselin, NextEra

7 Alan McBride, ISO-NE

8 Steven Naumann, Exelon

9 Rick Vail, Pacificorp

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11 PANEL 2:

12 David Angell, Idaho Power

13 Jennifer Ayers-Brasher, E.ON

14 Joshua Bohach, EDP

15 David Egan, PJM

16 Charles Hendrix, SPP

17 Randal Oye, Xcel

18 Stephen Rutty, CAISO

19 Kris Zadlo, Invenergy

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1 PANEL 3:

2 Tim Aliff, MISO

3 Dean Gosselin, NextEra

4 Paul Kelly, NIPSC

5 Omar Martino, EDF

6 Alan McBride, ISO-NE

7 Stephen Rutty, CAISO

8 Rick Vail, PacifiCorp

9

10 PANEL 4:

11 Tim Aliff, MISO

12 David Angell, Idaho Power

13 Jennifer Ayers-Brasher, E.ON

14 Daniel Barr, ITC Holdings

15 Charles Hendrix, SPP

16 Paul Kelly, NIPSC

17 Omar Martino, EDF

18 Steven Naumann, Exelon

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1 PANEL 5:

2 David Egan, PJM

3 Mason Emnett, NextEra

4 John Fernandes, RES Americas

5 David Gabbard, PG&E

6 Alan McBride, ISO-NE

7 Stephen Rutty, CAISO

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16 Court Reporter: Alexandria Kaan, Ace-Federal Reporters

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P R O C E E D I N G S

2 (9:00 a.m.)

3 MR. PAN: Good morning. Welcome to the
4 Review of Generator Interconnection Agreements and
5 Procedures technical conference. This conference will
6 focus on select issues from the AWEA petition on
7 rule-making, and other interconnection-related issues
8 including interconnection of electric storage. I'm Adam
9 Pan with the Office of General Counsel. This is a
10 staff-led technical conference and any comments made
11 here represent the views of Commission staff and do not
12 necessarily reflect the Commission's views. A final
13 agenda is available for attendees at the meeting room
14 entrance. There a few minor changes in the biographical
15 information.

16 We have a few housekeeping matters to note:
17 Please turn you mobile devices to silent. We also note
18 in the Commission meeting room no food or drink other
19 than water are allowed. If you need Wi-Fi information,
20 there are forms at the meeting entrance. You need to
21 sign the forms before you sign in. We will break for
22 lunch from noon to 1:00 p.m. There will be a morning
23 break from 10:20 to 10:30 a.m. There will be an
24 afternoon break from 2:10 to 2:20 p.m.

25 Speakers, please be sure to turn your

1 microphones on and speak directly into them so that
2 audience and those listening to the webcast can hear
3 you. Please turn your microphones off when you are
4 finished speaking. Panels 1 through 4 will be moderated
5 by Tony Dobbins, panel 5 will be moderated by Michael
6 Herbert. Thank you.

7 Commissioner Honorable is here. I don't
8 know if you wanted to take the opportunity to say a few
9 words.

10 COMMISSIONER HONORABLE: Thank you. Good
11 morning everyone. I'd like to thank the representatives
12 here from the various stakeholders groups, and in
13 particular there are a number of you that I've known for
14 a number of years, so you've seen me try to transition
15 from being a state regulator and now a federal
16 regulator. And more importantly, I appreciate the ways
17 in which you've attempted to educate regulators about,
18 not only the important resources that we're attempting
19 to ensure stay not only in the queue but integrated
20 well, but also ways in which you're educating us, and me
21 and my staff in particular, about the barriers of some
22 of the concerns and issues that you're having in the
23 interconnection process.

24 Generation interconnection queue issues have
25 the potential to negatively affect the competitiveness

1 of our markets and the reliability and resilience of our
2 grid. And I believe that these processes can not and
3 should not be a barrier to entry for needed generation
4 capacity, for variable resources, or energy storage, if
5 we are to maintain a robust and reliable power system.

6 In particular, during my tenure here at the
7 Commission, I've had a number of very robust discussions
8 with a number of you regarding experiences that you have
9 had navigating the interconnection queue process, and I
10 have heard you loud and clear, as have my colleagues
11 here at FERC and my staff, and I'm very pleased that
12 under the direction of our Chairman and my colleagues,
13 we have approved this technical conference.

14 I'd like to thank our very capable staff who
15 have worked very, very hard, as you can tell from the
16 agenda, we will cover a lot of ground today, and that's
17 why we're here an hour earlier, so thanks to those of
18 you who actually read the notice.

19 But our purpose here today, and in
20 particular I'm interested in hearing about not only
21 concerns and issues that you're experiencing with regard
22 to the queue process, with interconnection agreements,
23 also I'm particularly interested in hearing about the
24 study process in ways we can improve this work. I was
25 joking I think with Rob Gramlich that we are looking to

1 you all for the silver bullet. Maybe there isn't one,
2 but I'm hopeful that through our dialogue throughout the
3 day that we will hear from you. You all are the
4 experts, maybe proposals for the solution, because I
5 think we all share in common that we want this to work
6 well to ensure we have robust markets, and ultimately
7 that we are providing diverse, reliable, and affordable
8 energy for the people that we serve.

9 So I'd like to thank all of you for your
10 attendance here today, I look forward to hearing you
11 comments, and thank you for the opportunity to
12 participate.

13 MR. PAN: We'll begin our first panel at
14 9:20. So we ask that all staff and panelists be seated
15 and prepared at that time.

16 MR. DOBBINS: We're going to go ahead and
17 start panel 1 at this time, which is to discuss issues
18 related to the current state of the generator
19 interconnection queues. We are starting five minutes
20 earlier than in the agenda, so everyone please take note
21 of that. I'm sure that additional five minutes will be
22 well deserved for a topic such as this.

23 We will ask panelists to introduce
24 themselves and present their prepared remarks which were
25 submitted to the docket or mention the one or two most

1 important points they would like us to come away with
2 today. Please keep your remarks under two minutes. We
3 will use the timer, which the panelists can see upfront,
4 to let them know how much remaining time there is. And
5 we'll start on my left with Mr. Tim Aliff.

6 MR. ALIFF: Thank you. Good morning. My
7 name is Tim Aliff, I'm director of reliability planning
8 with MISO. My purview includes the generation
9 interconnection process.

10 MISO has always been looking to improve the
11 interconnection queue process; we've done that over the
12 last almost 10 years, including three different queue
13 reform proposals that were successful in moving the
14 process forward, making the process better. Today we're
15 experiencing challenges in our queues specifically
16 related to delays and how long it takes for units to
17 move through the queue process. And we are working with
18 our stakeholders continually and through our
19 interconnection process task force and then also working
20 with the Commission and the guidance that we received
21 through the Commission on how we can make our process
22 better.

23 One of the things related to being at the
24 FERC level here is that we want to point out that each
25 of the regions, each of the transmission providers, have

1 unique differences that need to be at least respected,
2 if you will, in the interconnection process. One size
3 doesn't fit all from an interconnection queue process,
4 something that works in a one-state RTO may not work in
5 a multistate RTO such as the MISO.

6 And specifically within the MISO, the
7 multistates, each of the states has their own view on
8 renewable portfolio in that state. And so recognizing
9 that difference and also the flexibility that provides
10 to each of the regions and being able to move that
11 interconnection queue process forward and to the benefit
12 of the stakeholders moving through, and also to ensure
13 the reliability of the transmission group going forward.

14 MR. DOBBINS: Thank you.

15 MR. GABBARD: Good morning. My name is Dave
16 Gabbard. I'm director of electric generation and
17 interconnection at Pacific Gas and Electric Company. My
18 team's responsible for interconnection generation to
19 both PG&E's transmission and distribution systems.
20 First, I want to thank the Commission for the
21 opportunity to participate today.

22 Under the direction of the California ISO,
23 PG&E has safely and reliably commissioned over 6,200
24 megawatts of generation over the last 10 years. We have
25 an additional seven gigawatts of active generation in

1 the CAISO queue progressing towards interconnection on
2 the PG&E transmission system. In addition PG&E has
3 interconnected over 400 megawatts of distribution
4 generation to its distribution system under its
5 wholesale distribution tariff, and has an additional 400
6 megawatts of generation in its queue.

7 PG&E has both witnessed the legacy issues
8 impacting the transmission interconnection process and
9 the tariff reform led by the California ISO to mitigate
10 these issues. PG&E commends the California ISO for its
11 efforts to lead industry collaboration and stakeholder
12 processes that result in an enhanced interconnection
13 tariff, that helps mitigate queue management, backlog,
14 and transmission overbuild challenges. That said, the
15 solutions developed within the California ISO territory
16 are unique to the environment and stakeholders involved
17 within the CAISO interconnection process.

18 While PG&E supports benchmarking across
19 regions for lessons learned, PG&E does not recommend
20 forcing region-specific solutions across other RTOs and
21 stakeholders. Maintaining a regional flexibility at the
22 interconnection process will allow RTOs, PTOs, and
23 generator stakeholders to continue to refine processes
24 and tariffs to accommodate transmission generation
25 interconnection in an evolving market landscape. Thank

1 you.

2 MR. GOSSELIN: I'm Dean Gosselin with
3 NextEra Energy Resources. I'm vice-president of
4 business management transmission services. We are a
5 developer owner operator of renewables across the
6 country. What we find is the process of the system
7 impacts study on the interconnection queue process'
8 result is a key input to every one of our projects; its
9 costs and the timing of those facilities, are necessary
10 to make a determination of whether a project is viable
11 or not.

12 So at the beginning of a process when we
13 think about entering a queue, what's important is that
14 we have valid solutions coming back to us in a timely
15 manner and that they're accurate, that they're accurate
16 in what they say.

17 The issues that we see is there's lots of
18 restudies going on now. So at the initial offset of a
19 queue or of a group study, there's a lot of generators,
20 new generator requests, that won't be built. And as the
21 queue progresses and they begin to get answers back,
22 they drop out. And that destabilizes the queue, and
23 then the queue process starts again.

24 So what we're seeing is more and more
25 entrants, more and more megawatts coming at any given

1 study queue, and then many restudies having to drag out
2 the process of determining ultimately who's left and
3 what are those costs and schedules for system upgrades.
4 So what we need is an optimal solution, that's the tough
5 part. Right? I don't think anybody in the country has
6 an optimal solution today. There are pieces of good,
7 everybody's working towards it, nobody's trying to
8 impede it. But it's difficult when that queue is not
9 stable, at least the study entities are not stable.

10 Thank you.

11 MR. McBRIDE: Good morning. My name is Alan
12 McBride. I'm the director of transmission strategies
13 and services at ISO New England, and my responsibilities
14 include the oversight of the interconnection queue. I
15 want to thank the Commission for the opportunity to
16 speak here today.

17 ISO New England has been working with the
18 interconnection issues with our stakeholders. And the
19 ISO's recent filing with the interconnection
20 improvements was approved by the Commission on April
21 15th. That filing contained important clarifications of
22 data modeling, requirements for new generation, in
23 particular for inverter-based generation. It also
24 included the clarifications of the ISO's material
25 modification review process, as well as the

1 establishment of dynamic reactive power factor
2 requirements for wind generation.

3 The ISO's continuing to work with
4 stakeholders on interconnection improvements. We're
5 currently undertaking a discussion of different
6 approaches to clustering, and we are investigating the
7 identification of new transmission infrastructure that
8 could be used to interconnect multiple interconnections.

9 Our considerations have included a survey of
10 clustering approaches used by transmission providers
11 including ISOs and RTOs throughout North America. The
12 surveyor identifies some useful features and practices.
13 It also highlighted the importance of regional
14 differences in the appropriate design of interconnection
15 practices, as there are different needs in each local
16 area driving the development.

17 For example, in New England, the
18 interconnection process is integrated with the
19 forward-capacity markets, and that is an integration
20 that is working well; I can talk about that later if we
21 need to. The ISO also noted meaningful differences in
22 approaches to ratepayer support for network upgrades in
23 different regions.

24 Within New England, the ISO has identified
25 differences in the rate of progress of interconnection

1 request depending on the technical challenges. There
2 have been a large number of requests that are
3 geographically concentrated in a over-subscribed area of
4 the system that is already at its performance limit. So
5 our current work is to identify potential solutions and
6 move that process forward. Thank you.

7 MR. NAUMANN: Good morning. I'm Steve
8 Naumann, vice president of transmission policy at
9 Exelon. Thank you for asking me to speak here.

10 As you have heard, there have been a lot of
11 improvements in the processes since 2003, especially
12 within the ISOs and RTOs and they've been working with
13 their stakeholders. We agree with some of the requests,
14 such as increasing transparency, having access to the
15 models. But many of these requests would result in
16 asymmetrical shifts and risks from the interconnection
17 customers, and that's something we do not agree with.

18 While there have been improvements, the
19 system has also changed since 2003. We have serious
20 concerns about implementation process for ERI
21 interconnections because of the impact on existing
22 resources. The ERI generators use "as available
23 transmission capacity."

24 But in midbase market environments without
25 proper analysis, it matches the way the systems operate.

1 These generators can be allowed to cause additional
2 congestion, and that congestion has caused harm to
3 existing base load units that can no longer withstand
4 the financial harm that is being done to them.

5 To be more specific, along the lines of not
6 harming existing customers when considering new
7 interconnections, new interconnection resources that are
8 most likely to impact the system need to be, as I said,
9 studied as they operate, not necessarily at peak load.

10 So what you need to do is look how they're
11 operated, and obviously combined cycle may be on a peak
12 load but other intermittent resources are not. And in
13 those cases, light load needs to be studied for
14 congestion and reliability. This is a best practice in
15 PJM, and it's also being done here. Thank you.

16 MR. VAIL: Good morning. I'm Rick Vail, I'm
17 the vice president of transmission with PacifiCorp.
18 Some of the areas under my responsibility are generation
19 interconnection queue, the transmission planning staff,
20 as well as all of the capital budgeting that's
21 associated with the transmission system at PacifiCorp.

22 So PacifiCorp has what I would call a
23 well-established queue process. I will say we're under
24 that mode of continuously evaluating it, getting
25 feedback from our customers, and trying to improve what

1 that queue process is. It is a serial queue process;
2 PacifiCorp is not currently part of any regional ISO, so
3 it may be a little bit unique or different perspective
4 than some of the other entities here.

5 PacifiCorp has processed roughly 750
6 interconnection requests, about 20 percent of those end
7 up going into service. Over time we've had a higher
8 percentage of the projects go into service, a lot of the
9 requests that we get seem to be a little bit of a
10 fishing expedition in trying to determine where within
11 the transmission system is probably the most appropriate
12 place to attach for generators.

13 I think one of the main issues or concerns
14 from a PacifiCorp perspective is that we get a
15 significant number of requests in small geographic
16 areas, and that can put a lot of stress and pressure on
17 the existing system, especially from a reliability
18 standpoint.

19 So some of the kind of suggestions that
20 we've looked at is trying to minimize what the suspend
21 status of higher queue projects is, that really can have
22 a big impact on the uncertainty that developers face
23 when higher queue projects drop out, and I'll talk a
24 little bit more on that as we go forward.

25 One other concept we have to consider is

1 just trying to increase the deposit requirements and
2 financial security backing as some of these developers
3 come in. The more sophisticated developers are very
4 well-aware of what the requirements are, as we get some
5 more sophisticated developers that can kind of bring a
6 lot of volume to the queue that may or may not end up
7 going forward. So thank you.

8 MR. DOBBINS: All right. Thanks to all of
9 our panelists on panel 1 for their time and
10 participation for today and their opening comments. And
11 I'd also like to acknowledge Commissioner LaFleur who
12 has joined us, and we thank you for your attendance and
13 participation. And before staff moves on to ask
14 questions, I wanted to see if you would like to make any
15 comments.

16 COMMISSIONER LaFLEUR: Well, thank you. I
17 am happy to be here. I had an appointment out of the
18 office; it's hard to find a day when there's no tech
19 conference to schedule things. Sorry I missed the first
20 panel, but I look forward to the conversation. I think
21 the topic of today covers a lot of important issues, so
22 look forward to hearing it. Thank you.

23 MR. DOBBINS: Okay. Well, now we're going
24 to move on to our staff here from FERC asking questions.
25 Panelists, please limit your responses to around a

1 minute so that other panelists will have time to speak
2 and we can cover as many topics as we can. And
3 apologies in advance if we aren't able to hear from
4 everyone on every topic.

5 I'll start us off with the first question.
6 We've had, through your comments filed in the docket and
7 also some of your remarks and introduction, an
8 indication of improvements made in the queue process,
9 but also areas where, you know, there are challenges.
10 We would be interested in getting your general overall
11 thoughts on how the queue process is working and if
12 there are any clear areas for improvement, if you've
13 targeted solutions there. And we'll start off on my
14 left with Mr. Aliff.

15 MR. ALIFF: Thank you. So first, how is the
16 current queue working? As I mentioned in my opening
17 remarks, we understand there are challenges related to
18 delays in the queue that's mostly related to restudies,
19 as you heard in some of the opening remarks, projects
20 withdraw and then be have to restudied. We're seeing
21 withdrawal rates over 50 percent in lots of parts of the
22 queue, specifically in our northern areas where it's
23 more congested.

24 As far as metrics that we've implemented, we
25 measure the cycle times, how far behind are we on our

1 queue, and we're currently on it close to about a year
2 behind in our queue processing. So some ways that we
3 present that make that clear, transparent to our
4 stakeholders as we provide that through stakeholder
5 meetings, we provide that on our website so you can see
6 how far behind we are in the projected dates for
7 completion of the queue.

8 As far as the process improvements,
9 discouraging non-ready projects, the projects that are
10 likely to withdraw moving through the queue, reducing
11 the amount of restudies, having more scheduled restudies
12 in the process rather than unforeseen restudies. Also,
13 clear requirements related to everyone involved. Clear
14 requirements for the interconnection customers providing
15 information, the transmission owners performing studies,
16 and then MISO as well performing studies and meeting
17 timelines. Thank you.

18 MR. DOBBINS: And before we move on to our
19 next response, I just wanted to get a clarification on
20 your saying over 50 percent withdrawal. Is that, in
21 your opinion, mostly due to projects who aren't really
22 ready to move forward and were testing the water, or is
23 it projects that they got in the queue, found out that
24 information they need, and from a business standpoint
25 have decided it's not a viable project moving forward?

1 line of the panel to see if anyone else would like to
2 address the original question, which was: Your general
3 thoughts on effectiveness of the queue and if there were
4 areas that are easy areas for improvement. And please
5 understand we have your responses, which have been filed
6 in the docket. So if you don't want to -- if you
7 haven't addressed this in your docket, also please feel
8 free -- sorry, in filing the docket -- please feel free
9 to offer any information here.

10 MR. GABBARD: Again, I'm Dave Gabbard,
11 director of electric generation at PG&E. I just want to
12 touch on a couple of points. I think the specific
13 enhancements to the interconnection process in the
14 California ISO service territory are unique to the
15 configuration and different characteristics of operation
16 in that territory.

17 But I do want to call out and acknowledge
18 the process in which we have evolved the interconnection
19 processes over the last five years specifically. There
20 have been macro reforms to the tariff, but also the
21 California ISO has led interconnection processing
22 enhancement stakeholder discussion that have allowed us
23 as a collaborative set of stakeholders to identify
24 issues and then find solutions that work for all
25 parties. As a metric for identifying the success of

1 those enhancements, I would acknowledge the amount of
2 generation that is being interconnected on an annual
3 basis.

4 I don't think that fallout is a good metric
5 for whether or not a process is successful other than
6 the fact that fallout of nonviable generation earlier in
7 the project is proof of success. So the process we have
8 in place within the California ISO service territory and
9 specifically within the PG&E service territory allows
10 for generation to come in and identify the impacts to
11 the grid from interconnecting a proposed generator. But
12 it requires a certain level of commitment with respect
13 to the process and allows generation that's nonviable to
14 withdraw earlier in the queue, allowing more viable
15 generation to successfully progress through the queue,
16 effectively without too much overheated and overbilled
17 challenges going forward.

18 From a timeline perspective, both on our WDT
19 side, the wholesale distribution side, as well as within
20 the CAISO process, we are up to speed with tariff
21 timelines and progressing interconnection queues and
22 serial request in a timely manner in compliance with our
23 tariffs. And we have seen those projects successfully
24 move forward to completion. The delays that are
25 experienced within the process have happened on both

1 sides, the interconnection customer who participated and
2 transmission owners. It's at various stages. Need for
3 financing and other things naturally cause certain
4 delays at certain phases, but the overall progression
5 towards cooperation continues through actively and our
6 processes are set up to support that. Thank you.

7 MR. GOSSELIN: Dean Gosselin with NextEra
8 Energy Source. I'd like to just talk about what is
9 optimal. We were thinking about it, as a developer we
10 were bringing a new project idea and trying to advance
11 it to fruition, "fruition" being completion of the
12 project. I would say for the interconnection queue that
13 the initial results closely match final results in a
14 defined and reasonable timeline, that would be my
15 definition.

16 So all of the RTOs really provide us models,
17 they give us their models and they're repeatable,
18 they're accurate. The problem with us running the
19 models -- and we do that in advance of submitting a
20 project, and we look at the results and if they look to
21 be expensive or costly and a long schedule to do
22 upgrades, we are not putting in a request because it's
23 not going to go anywhere, it just doesn't work; not in
24 our schedule, not in our cost, and not in the RTO's.

25 However, what we don't know is who else is going

1 to enter that queue with us, and what is the cumulative
2 impact of that group. And we can't know that, it's
3 unknowable at the time in which we put in a request.
4 And that is I think one of the fundamental issues with
5 queue timing and schedule and accuracy of the study
6 process coming out of it. That's obviously the area of
7 challenges: Stabilizing the group to the point where
8 the study that goes on, the final study that goes on,
9 gives you valid results.

10 And the results are, I don't think any of us
11 -- certainly NextEra does not believe we're getting
12 invalid results, it just believes we're getting a lot of
13 restudies that stretch out the timeline. And we have a
14 saying in our world of development which is time kills
15 all projects. So the longer it takes, the more unlikely
16 it is that a project will be valid and go to fruition.
17 Thank you.

18 MR. McBRIDE: Alan McBride, again, with ISO
19 New England. Many of us have been thinking through your
20 question, we want to make sure we were careful to
21 identify what was working well and what was not working
22 well, and not approach it from just generically "there
23 are queue problems."

24 In New England, we study energy
25 interconnections in serial queue order, and then we

1 integrate the queue with the forward-capacity market and
2 what's effectively an annual group study or annual
3 cluster. That would be very important that that works
4 well, we have a sufficient number of generation that's
5 seeking to participate in the forward-capacity market
6 successfully, be able to qualify and do so, and that has
7 been going well over these past few now 10, going onto
8 our 11th, forward-capacity auction.

9 The problem we do have is in a specific part
10 of the system that's already at its performance limit,
11 we have a significant number of interconnection
12 requests, mostly are pretty much exclusively for
13 renewable interconnections. So that is the diagnosis of
14 the problem, and then we went down the path to see what
15 would be appropriate solutions to that.

16 The first step was we did identify some
17 issues with the performance of the particular type of
18 generation and we saw some benefit in making clear that
19 we were communicating appropriate expectations for what
20 the modeling and data should be that should be provided
21 that we can plug those into the models and get the study
22 done quickly, and we're already seeing some benefits
23 from that.

24 And then the remaining part of the solution
25 is the infrastructure challenge. It seems like it lends

1 itself to some kind of either a clustering solution or
2 some other solution to bring infrastructure to integrate
3 the requests that we have for that situation, and that's
4 what we're working on now.

5 MR. DOBBINS: And before we move on, I just
6 want to clarify you're saying moving to a
7 clustering-solution region why are you looking for a way
8 just to cluster the geographically constrained or
9 concentrated area?

10 MR. McBRIDE: I think that's exactly the
11 question we're asking ourselves and that we're going to
12 be working with with our stakeholders. We are very
13 cognizant of some of the difficulties of clustering and
14 with restudying and uncertainty. So we're looking at
15 ways, seeing if we can find a way to minimize the
16 uncertainty and the restudy and present something. It
17 could be specific locational and it could be something
18 more problematic. But we'd like to come up with the
19 best design possible to answer that very question.

20 MR. NAUMANN: Quickly, one improvement that
21 we're seeing in PJM is more clear requirements at the
22 beginning. So, for example, if a request is deficient,
23 it just gets kicked out of the queue, you don't have to
24 start working on it. But I think you've heard a theme
25 here, that is we need to have a robust and reliable

1 transmission system to integrate new generation and
2 provide reliable service to customers.

3 On the other side of that is the serial
4 impact of new interconnections and the option now that
5 was mentioned that earlier queue projects when they get
6 their results for any reason or no reason at all, and it
7 could be many reasons, maybe they put in for
8 alternatives; they only intend to build one, then three
9 of them will drop out. The higher queue projects drop
10 out, all those studies that were done now have to be
11 redone. And now if you get -- now you're shifting the
12 cost of the upgrades to somebody else and you may get
13 more dropouts or something.

14 That's the challenge. I don't think there's
15 a generic issue unless you start looking at a completely
16 different solution than what you're looking at. But
17 short-circuiting that process to say, "We're going to
18 take the initial answer." Well, that could mean you're
19 building more than you need, which might be good in the
20 long run, or, "We're going to kick people out before
21 they want to because they're "speculative." None of
22 those are necessarily good answers. So it's a tough
23 answer and may have to look at how do these upgrades get
24 done and how do they get funded?

25 But the first thing that needs to be agreed

1 upon is that there will be a robust and reliable
2 transmission system both for the interconnection
3 customers and for the load customers who ultimately pay.
4 Once you get that process, you can start debating about
5 how you make the other process faster or more optimal to
6 use the tariff. But we need to start with a process
7 that gives us that reliable, robust transmission system;
8 don't build congestion into the system, don't build
9 reliability problems into the system. It's not
10 necessarily a target enhancer, but I think it's a high
11 level identification of the issue.

12 MR. VAIL: Rick Vail with PacifiCorp. I
13 probably echo a lot of the same comments I heard on the
14 panel here, no question about it. I think one other
15 thing I would probably add into that is one of the
16 responsibilities as a transmission provider is to make
17 sure we're not passing on some of these costs to connect
18 additional generation, especially if it's not required
19 for load service of native retail customers onto our
20 other transmission customers. So we're very
21 customer-focused for both, not only our transmission
22 customers, but any of the generators that want to
23 connect to the PacifiCorp system.

24 With that being said, though, I think having
25 the time and the effort that goes into all the restudy

1 of impacts of higher-queue projects dropping out is
2 probably one of the biggest concerns, especially as I
3 mentioned in the opening comments when we have a smaller
4 geographic area where these renewable requests are
5 coming in and they're concentrated on a small geographic
6 area.

7 I think it also get complicated a little bit
8 more just because the way Pacificorp is set up, we're
9 very rural, the majority of the generation in our system
10 is hundreds, if not many hundreds, of miles away from
11 our load center. So you certainly have different areas
12 where you have transmission constraints but those also
13 continue to be the areas where we are often requested to
14 connect to the system as well, so.

15 MR. DOBBINS: I guess along the same lines,
16 understanding that there aren't generic issues across
17 regions, I have a question for Mr. Gosselin and
18 Mr. Naumann. Are there queue practices that you've seen
19 that work well that you would like to see implemented
20 across all regions?

21 MR. GOSSELIN: Dean Gosselin with NextEra
22 Regional Resources. One of the things that we find is
23 successful, is not used by all regions but at least a
24 couple of regions do, is they set forth fairly stringent
25 requirements, and one of those requirements is a show of

1 land control, that you have control of land to be able
2 to build a project that you're saying you want to
3 interconnect. That seems to work decently in terms of
4 keeping even our own projects that we would otherwise
5 have submitted out of the queue and keeping it from
6 clogging up from the initial standpoint. But in and of
7 itself, that's not sufficient.

8 I think from there on the stringent -- as
9 the study process progresses, stringent requirements and
10 basically financial liability certainly acts within
11 NextEra and our decision making process. It keeps us
12 very disciplined about what we keep in the queue. So if
13 we're at a point of process where we're responsible for
14 system upgrade costs, regardless of whether we go
15 forward or not, that is a true -- a point of decision
16 for us on whether we want to stay in or not.

17 Now, unfortunately, the interconnection
18 results, the cost and schedule, are important to decide
19 whether or not a project is viable, especially in
20 today's competitive markets where we're competing with
21 cost on everything. And our customers we're selling to
22 are suffering as well. They want to know there's a
23 valid interconnection and they're not signing up or
24 looking to enter into a power purchase agreement or some
25 form of commitment on a project that's not going to go

1 forward, they want projects that go forward as well.

2 So it's kind of egg and chicken here and
3 what goes first. Right? And until that group
4 stabilizes -- any tools that stabilize the group quicker
5 I think are necessary to get the valid results in the
6 timely fashion. Thank you.

7 MR. NAUMANN: Just to add to that, I think I
8 mentioned having clear requirements -- this is true at
9 PJM -- that the customer knows about, and that if you
10 don't meet them you're out of the queue and no one is
11 spending time doing evaluations on something that's not
12 quite right. Just to give an example -- and I know
13 you're going to talk storage in the last panel, but it's
14 an example of interconnection -- you get a customer, you
15 go through the study, study phase, several studies, then
16 they change the manufacturer of the inverter and it has
17 different characteristics.

18 Now you have to redo -- this isn't dropping
19 out, this is technically you have to redo the flicker
20 study. This is another study that has been occasioned
21 by a change that had that not been done you wouldn't be
22 spending your time. The other thing is not so much a
23 requirement, but it's really -- and it's something we
24 see as the transmission owner at PJM and also on the
25 other side as a generation owner, is continual meetings

1 between PJM, the TO and the customer on a regular basis.
2 Where you are; where the study is; where a problem is
3 showing up trying to short circuit the problem; making
4 sure everybody knows what's going on so you don't come
5 toward the long end of a study, and say "Oh, here's the
6 study. Oh, by the way there's a problem so now you have
7 to redo things over again."

8 So throughout the process, keeping in touch
9 and then taking the feedback where there have been
10 problems and feeding that back into your system to make
11 corrections. I think in addition to having stringent
12 requirements, communication becomes very important to
13 avoiding problems.

14 MR. DOBBINS: Thank you. I now have a
15 question for the transmission providers. Earlier,
16 Mr. Aliff, you referred to a withdrawal rate of about 50
17 percent and one-year delay in cycle time. I'm
18 interested and we're interested in knowing how all of
19 you evaluate your interconnection queue operation and
20 what metrics are used to evaluate the performance?

21 MR. ALIFF: So today we're evaluating the
22 delay, the time delay, as I mentioned before and we are
23 looking to develop further metrics related to that. But
24 today that is the metric that we are monitoring today.
25 Because of the interest in how long the process is

1 taking and we wanted to provide transparency to that
2 metric. We also provide other metrics that aren't
3 really related to the performance but what type of units
4 are coming into the queue, where are those projects
5 coming in -- so we see projects come in to our northern
6 part of the footprint, more because that's where the
7 wind-rich areas are, if you will, as we see a number of
8 projects coming into that area.

9 But we are seeing an increase of solar
10 coming into our southern part of our footprint and an
11 increase in gas with the changing fuel mix, if you will,
12 that we're expecting over the next several years.
13 That's something we keep track of and we provide that
14 transparency to our customers, but it's not really a
15 metric per se on the queue performance.

16 MR. DOBBINS: So in terms of a metric to
17 evaluate how well you're doing, would the withdrawal
18 rate and cycle time be the primary ones?

19 MR. ALIFF: Withdrawal rate provides some
20 information. As mentioned before, it can be a little
21 misleading depending on where that is being measured.
22 So a withdrawal rate late in the game and towards the
23 end of the study process is certainly more concerning
24 than a withdrawal earlier in the process.

25 If you can provide those, as mentioned

1 before, the site control or the milestones to prevent
2 that, the projects from entering the queue at first,
3 then that withdrawal rate should go down. But it kind
4 of depends on where it is in the process.

5 MR. DOBBINS: And we have that same question
6 for the other transmission providers: How is queue
7 performance evaluated and what are the metrics used for
8 evaluation?

9 MR. McBRIDE: So the headline metric for us
10 would obviously be the time from the middle of the
11 interconnection request to the completion of the system
12 impact study, that's the one we focus on the most. But
13 when looking at that headline metric, we look beneath to
14 see are there differences in different geographic areas?
15 And I talked about those a little bit. And are there
16 differences based on technology or technology type?

17 We did find differences in time taken
18 complete studies and restudies, data requests,
19 deficiency requests, based on technology type. The
20 newer technology, mostly inverter-based renewable
21 technology, is new. A lot of the manufacturers are less
22 acquainted with the data and modeling requirements that
23 are needed to get through a system impact study. It's
24 different from the traditional equipments that have
25 well-established data models and performance models that

1 have been in place for some decades now.

2 So we have put together some clear
3 guidelines and requirements, the tariff portions were
4 approved, that we think that were already helping that.
5 So for that situation where underneath the headline
6 metric, you have a particular, troubling area, we think
7 we can move that forward.

8 In terms of withdrawal rate, the withdrawal
9 rate in New England is quite low during the system
10 impact study phase. There are some cases where you'll
11 hear of a withdrawal because of a fundamental change in
12 the circumstances like a pipeline no longer being built
13 or no longer expected, might cause a gas generation to
14 withdraw. For the most part, we see withdrawals after
15 the system impact study, sometimes if the
16 interconnection upgrades are more than what was expected
17 by the interconnection customer.

18 We also see withdrawals after a resource
19 might have participated in the forward-capacity market
20 maybe one, two, or three times. If it's not clear about
21 that modification then we'll withdraw the project, and
22 that would be the end of the endeavor.

23 MR. VAIL: Rick Vail, PacifiCorp. So from
24 PacifiCorp's standpoint, we have dedicated project
25 managers who track each of these security parts all

1 through the different processes. We also have
2 established timelines in our open access transmission
3 tariff that we have specific timelines to meet.

4 So we're tracking as this goes through each
5 of the different processes from a timing perspective.
6 We also track at what stage each of our interconnections
7 is at, so the feasibility phase, impact study, or full
8 facilities study, and then where they are in the process
9 as far as getting billed. So there are a lot of metrics
10 around our process and over time we have continued to
11 add additional metrics. We do track in order to, again,
12 try to improve processes as much as possible.

13 I think the one area, as I've kind of
14 mentioned, when you start getting significant movement
15 in higher queue projects, especially in a specific
16 geographic area, I would say that's the one time from
17 PacifiCorp's standpoint is a real challenge to the meet
18 the timelines that we're required to meet on a steady
19 process.

20 MS. COCKRELL: So thank you for your
21 participation. A couple of times the production kind of
22 impacted those discussions. So I wanted to drill down
23 on that a little bit more and better understand to what
24 extent some of the backlogs you're saying are directly
25 related to projects being geographically concentrated,

1 and whether you come up with any reasonable solutions or
2 you're working on reasonable solutions to account for
3 the fact that there are a lot of requests, it sounds
4 like in certain particular areas and how to address
5 that.

6 I guess that's probably more for the
7 transmission providers on the panel more so than others,
8 but anyone can answer.

9 MR. ALIFF: Maybe I'll go first. Tim Aliff,
10 MISO. So we do see differences from the geographical
11 standpoint. It's usually related to where a lot of
12 projects are trying to move into an area that there is a
13 lot of congestion that the transmission system is not
14 necessarily built at the time if you will to support all
15 of the projects coming in. So it takes a little bit
16 more time developing the network upgrades, for those
17 projects to interconnect reliably.

18 And then there can be even more impact in
19 that area when a project withdraws, as you've heard
20 several times today. Those projects withdraw and then
21 have a greater impact on other projects and their
22 network upgrades costs. Areas that aren't so congested,
23 projects can withdraw, there's little to no restudy
24 through that. So it kind of varies.

25 One thing we've done at MISO is to split up

1 our queue process by geography so we have four different
2 areas that we're looking at in our footprint. So the
3 areas that aren't as congested can move quicker than
4 areas that are congested. Outside of the queue process,
5 MISO has taken steps to build that transmission system
6 to support those interconnection going forward
7 specifically related to our multi-value projects that
8 are looking to come in in the next several years that
9 would increase the ability in the north region upwards
10 of 26,000 megawatts of generation to interconnect in
11 that area, so outside of the queue process that is being
12 done as well.

13 MR. GABBARD: This is Dave Gabbard with
14 PG&E. I will just take the opportunity to give one
15 example of where we have a very overheated queue in a
16 geographical area and we were able to proceed forward
17 and continue to move viable generation towards
18 interconnection.

19 In our queue cluster 3 and 4 in the
20 California ISO service territory, we had a significantly
21 overheated queue in our Central Valley Area in Fresno,
22 California, triggering over a billion dollars worth of
23 upgrades to our transmission system. But through the
24 iterative process of the phase 1 study, phase 2 study,
25 and then subsequently annual reassessment, paired with

1 the financial security obligations of the process, we're
2 able to see viable generation post financial security to
3 proceed through the process, and then our iterative
4 cluster study reevaluated the impacts on the grid from
5 the less-heated viable generation queue.

6 And we have continued to progress generation
7 from that queue cluster towards completion. So the
8 iterative queue cluster process and the financial
9 security obligations embedded in our process have
10 allowed us to successfully mitigate that geographical
11 challenge. Thank you.

12 MR. GOSSELIN: Steve Gosselin with NextEra.
13 I don't have a lot to add on just the terms clustering
14 and how you deal with the clustering of resources in a
15 certain subregion. But I did want to just emphasize
16 that locationally constrained resources like wind, it
17 matters tremendously in terms of the overall cost
18 per-unit of production, as finding a windy area is very
19 meaningful to that equation. So the windier it is, the
20 lower the price, the cost, the lower -- and price
21 matters in the marketplace. So clustering usually
22 happens because of that, because there's a good wind
23 resource in some spot.

24 MR. McBRIDE: Alan McBride with ISO New
25 England. To drill down a little bit more on the

1 geographic piece, there is, of course, the first piece
2 is just a lot of requests in the same part of the
3 system. But, for example, in New England, we have that
4 in Maine, and I've talked about that being a challenge,
5 but we also have that, a lot of requests, in what we
6 call southeast New England, and those requests are in
7 response to that being import-constrained zones in the
8 forward capacity market.

9 And there is a relative difference even
10 there in terms of the rate of progress of those, and
11 comparing to each other. And what drives that is not
12 just the oversubscription, but the nature of the system
13 in the particular area. So in Maine, it's a system
14 that's already fully stressed and hard to bring in
15 imports from New Brunswick. But it's also these
16 requests are very different from load, they're very
17 different from the existing transmission system, and
18 they are inverter-based in nature. So it's the level of
19 subscription but also the underlying technical
20 characteristics of the system that the interconnection
21 customers are seeking to interconnect to.

22 MS. COCKRELL: Any other responses?

23 MR. QUINN: So I wondered if anyone had
24 thoughts on the degree to which the transmission
25 planning process can address, or be concerned to having

1 to address, some of the challenges that you get with
2 geographically clustering resources?

3 MR. NAUMANN: Well, this is what I was
4 trying to allude to. MISO stakeholders have chosen to
5 do this and at PJM we have a different process that
6 follows the but-for process that the interconnection
7 customers should be the ones to pay for the upgrades.
8 So as Rick said, so that the load customers don't end up
9 paying for it. That's a philosophical difference that
10 maybe the Commission has to look at again.

11 I'd be glad to have that conversation, I'll
12 tell you now I'll come out on where we are in PJM, but I
13 think it may be worth having that conversation because,
14 as I said, and I think everyone agrees, to interconnect
15 and to run the system you need a reliable system, a
16 robust system that matches how you operate the system.

17 Against that, as people have said,
18 especially locational-restrained resources, are
19 generally being connected to a system where it's weak,
20 and they require a lot of upgrades, and a lot of
21 upgrades are expensive. And then as the first customer
22 in the queue says that's too expensive, drops out or
23 part of that queue shifts it to others in the queue, you
24 now have to have restudies.

25 So it may be the time to generically look at

1 how do you plan? But if you do that, you need to
2 understand that may end up shifting those costs,
3 possible overbuilding, to the load customers. And that
4 will have consequences, I would suspect, state
5 regulators would like to be present at the panel to
6 discuss that. I'm not saying that's not a solution, but
7 you need to start "what do we need?" And after you say
8 "What do we need," how do we get there? And then you
9 create other issues on how you get there.

10 So it works for MISO, they've had buy in
11 from their stakeholders, and that may be a unique
12 solution to that area. That's not where we are in PJM.
13 But it might be worth looking at something in between in
14 order to get a system that you don't have this upgrade
15 by upgrade.

16 MR. GOSSELIN: Dean Gosselin with NextEra
17 Energy Resources.

18 So I have a different view on that. As I
19 think the MVP projects have been -- certainly I can tell
20 you that projects we considered a decade ago that were
21 not valid projects at that time because of upgrades and
22 not being able to move them on the system, have become
23 feasible again and we're looking at them and dusting
24 them off and saying are they projects for the future?

25 So we think it's a good idea. We saw that

1 in ERCOT CREZ where they built major backbone
2 transmission in advance of resources coming on, and that
3 has brought the price of the cost of the market down,
4 pricing of the market down and that's good for America.
5 And we think transmission enables that, especially with
6 this certain progression of renewables that we're
7 seeing. Thank you.

8 MR. VAIL: Rick Vail with PacifiCorp again.

9 Just from a transmission planning
10 perspective, I would say the planning process is already
11 pretty robust in looking at -- it's no secret where the
12 main areas core renewable development are going to be,
13 from PacifiCorp standpoint, looking at Eastern Wyoming
14 and the wind capacity out there. One of the
15 difficulties starting with that planning process is the
16 time it takes to build a significant transmission
17 infrastructure. If you go back to 2005-2006, a lot of
18 load growth, there was a lot of wind development that
19 had the potential to happen.

20 Then the economic crisis hit us. So a lot
21 of those projects and a lot of that load growth slowed
22 down and things were generally put on hold. And
23 PacifiCorp has been in the middle of permitting some
24 pretty significant transmission infrastructure. But you
25 do have to take into account that long timeframe to get

1 a significant transmission improvement permitted and
2 built.

3 And I think that brings definitely some risk
4 and uncertainty not only to the transmission provider
5 but to the developers as well. And again, I just go
6 back to another comment you have to make sure that
7 throughout this long process that those costs are not
8 being borne by the load serving, the load customers.

9 MR. DOBBINS: Are there any other comments
10 on this topic? If not, before we move on, I'd like to
11 acknowledge the attendance of Commissioner Clark, and to
12 thank you for coming. Right now we're talking about
13 general queue effectiveness metrics and geographic
14 concentration. Did you want to make any remarks or ask
15 any questions on this topic?

16 COMMISSIONER CLARK: Having just got here, I
17 don't have any questions at this point. But just
18 welcome to everybody, thanks for being here and everyone
19 in the audience as well. It seems like generator
20 interconnection issues and queue reform issues have been
21 something I've lived with for about 16 years because I
22 happened to be on a state commission, as about 1,500
23 megawatts of wind power connect into the state's grid
24 over the years.

25 So I was there, and then since coming to

1 FERC it's been one of those things we hear about from
2 time to time. It's one of these issues with the advent
3 of renewable resources that we're seeking to
4 interconnect on the grid that I think we just need to
5 stay on top of and to ensure that the rules are working
6 as they're intended to. Every now and then, I think we
7 just need to make sure that they are and make sure the
8 queue reform process were appropriate.

9 So I thank the Chairman for scheduling this,
10 for the staff for putting it together, and looking
11 forward to having a good record.

12 MR. DOBBINS: And I believe we have a
13 question from Commissioner LaFleur.

14 COMMISSIONER LaFLEUR: Well, thank you,
15 Tony. Arnie and Steve kind of teased out what was is
16 going through my mind, which is where does the
17 interconnection process leave off and the transmission
18 planning process start? And with the references to MVP
19 and CREZ? And I guess picking on Alan from ISO New
20 England, where you see a clustering of continued
21 requests interconnection in a particular region with a
22 renewable potential -- I presume you're talking about
23 Maine in your comments -- is there any feedback loop
24 from the interconnection process and the queue to the
25 transmission planning process where that may be an

1 opportunity for regional transmission line driven by
2 public policy requirements that could be like the
3 facilitator then of the specific interconnections in the
4 same way that an MVP was in MISO? And I guess I'm
5 wondering if there's any connection between these queues
6 and that process and then the planning process?

7 MR. McBRIDE: Thank you, Commissioner. The
8 cost allocation discussion in New England, I think like
9 everywhere, is a big discussion when it comes up, and
10 going back over the years of the framework that's
11 becoming developed. In New England, we have the
12 interconnection space, we have the but-for, the
13 interconnection customer will pay for only the upgrades
14 that are needed but for its interconnection.

15 Along with that, in New England, interconnection
16 customers do not pay for transmission service. And just
17 to kind of throw out some commentary on that some of the
18 thinking behind that was that would lead or incentivize
19 generators proposing resources to locate in a place
20 where there would be fewer upgrade requirements. It
21 would be easier to upgrade. It would be quicker to
22 upgrade, especially would align that incentive and to
23 keep their upgrade costs down.

24 But as we've seen and discussed, that
25 doesn't always work, especially when the resource is

1 just far away from the transmission system, which is
2 what we have in Maine. So we are looking at clustering
3 approaches, first of all, to see if a clustering
4 approach would work in that context through the
5 interconnection process. We don't have a design -- in
6 our current world, we don't have such a thing in our
7 interconnection process.

8 So we're seeing if that's achievable, and
9 other regions could have something that would support
10 it. Transitioning then to the public policy piece that
11 is under Order No. 1000, we're going to be kicking off
12 our first round of public policy next year at the
13 beginning of 2017. And that may be, under our process,
14 something that people bring up and want to talk about,
15 and it would be discussed in that context.

16 COMMISSIONER LaFLEUR: Thank you very much.
17 I would just comment that if you were building out your
18 system in what we'll call it traditional approach for
19 reliability where your transmission was keyed to where
20 your major resources were your population centers, the
21 concept that many people pay for interconnections by
22 where they locate because you want to incentivize them
23 to locate in an efficient place -- that's how it was
24 always done, that makes perfect sense.

25 When you start to overlay building out your

1 systems to meet public policy requirements, the Clean
2 Power Plan -- I forget what they call it in
3 Massachusetts, the Global Warming Solutions Act if I'm
4 not mistaken -- and a host of other environmental
5 aspirations. The paradigm that if you just hook into
6 the existing system you'll get what you need, just seems
7 to not maybe work in the same way. And that's why these
8 breakthrough process like CREZ or MVP are having that
9 impact, to the extent that there's a decision on the
10 part of society that meet those public policy
11 requirements. I think that's more of a comment. Thank
12 you.

13 MR. DOBBINS: Yes.

14 MR. NAUMANN: I think the difficulty in what
15 Commissioner LaFleur described is a general change in
16 the philosophy of planning from the but-for that many of
17 the regions use to almost an integrated resource
18 planning. It's worked in several regions, and ERCOT of
19 course that's a single state, and MISO there's a lot of
20 buy-in by the state regulators. You need to have all of
21 the states come together and say we're going to accept
22 these charges on our customers.

23 And that is I think, someone who's been
24 involved in litigation on one of these things for 12
25 years at least, is difficult. So you're going to have

1 that kind of paradigm shift. And, again, I want to come
2 back you want a robust system that doesn't end up with a
3 reliability or congestion problems.

4 And that out of paradigm shift, you're going
5 to have to get the state regulators here. Because in
6 the end, you can plan anything you want, but if they
7 don't site the lines it's not going to matter. So
8 you're going to need them at the table to have that
9 discussion. In PJM, the public policy is handled
10 through a state agreement, where the state would say, "I
11 have an RPS requirement and therefore I want this
12 transmission built and I am willing to have the
13 customers in my state pay for them."

14 A little harder when you start impacting
15 multiple states. So it is a further conversation, and I
16 would suggest not an easy conversation but maybe one
17 that is worth happening, if the goal is to end up with a
18 reliable system that doesn't introduce congestion. And
19 in the end just to say again, kicking off some of the
20 diverse resources that you're going to still need to
21 keep your system running at peak load and get you
22 essential reliability sources.

23 MR. DOBBINS: Would anyone else like to
24 comment on this? If not, staff, are there any questions
25 from FERC staff on this topic before we have a break?

1 No additional questions. All right.

2 At this time, we're going to take a
3 12-minute break until 10:30. At that point we will have
4 our next panel. All right, thank you.

5 (Whereupon a short recess is taken.)

6 MR. DOBBINS: If everyone will take your
7 seats, we're going to jump into our next panel. So we
8 welcome everyone back. We're going to begin panel 2,
9 which is Transparency and Timing and Generation
10 Interconnection Study Process. We're going to ask the
11 panelists -- sorry, please hold on for one moment.

12 We're going to ask the panelists introduce
13 themselves and make the prepared remarks that they
14 submitted in the docket or just to indicate the one or
15 two most important points they would like to make today.
16 Please keep your remarks under two minutes. We will use
17 a -- there's a timer at the front to let panelists know
18 how much time they have left.

19 And, Mr. Angell, please start.

20 MR. ANGELL: Thank you for allowing us to be
21 with you today. I'm Dave Angell, I manage planning for
22 Idaho Power Company. We're a company that serves
23 Southern Idaho and we're vertically integrated. And
24 we've been processing 500 interconnection requests since
25 2001. And we found that if we hold ourselves and the

1 customers to the timelines given by the FERC existing
2 process, we're able to manage the queue.

3 And we started with some flexibility in the
4 beginning but found that by providing that opportunity,
5 it gets abused and one can't really manage a queue. We
6 also find that we do have quite a bit of churn in the
7 queues as well, we only take about 20 percent of the
8 projects to construction and service.

9 So there are restudies that we do undertake,
10 and that restudy process, though we are typically able
11 to manage that within reasonable periods of time and not
12 having to extend the queue. Mostly the extensions of
13 time -- so our time range ranges from about 18 months to
14 about 24 months -- to process through the queue. And
15 the variance there is, quite frequently or mostly,
16 caused by the interconnection customer providing
17 inaccurate data, insufficient data, or changing their
18 interconnection request itself. And with that, I will
19 leave it for the rest of the panelists.

20 MS. AYERS-BRASHER: Good morning. My name
21 is Jennifer Ayers-Brasher and I'm the transmission and
22 market analyst at E.ON Climate and Renewables. And we
23 have over 2,700 megawatts of renewables in service
24 across the country. And we want to thank the Commission
25 and staff for the opportunity to speak here today and

1 hold the conference.

2 One of our primary takeaways for today is
3 the need for higher accuracy, accountability and
4 transparency in the interconnection process. Delays and
5 lack of transparency are harmful for generation. E.ON
6 has projects that have been in the system for five
7 years, and in that, as an example, limits our
8 opportunity to move other projects forward. We've also
9 had to withdraw projects due to lack of transparency.
10 One example would be when affected system costs were
11 brought in very late to the process and increased the
12 network upgrades by 14 million dollars in addition to
13 what we were already expecting, which made the project
14 unviable -- from the queue, and that's not ideal to the
15 system.

16 And so those transparent issues needed to be
17 brought up early. And these are just a few examples
18 that we've experienced. The interconnection process has
19 some flaws, and there have been improvements, and there
20 have been reforms and we appreciate that. We need more
21 improvements and we think the forum by FERC will
22 definitely move things forward. Thank you.

23 MR. BOHACH: Good morning. My name is Josh
24 Bohach. I'm senior development manager for EDP
25 Renewable North America. EDPR North America and our

1 subsidiaries, we develop, construct and operate wind
2 farms and solar parks throughout North America. We have
3 approximately 37 wind farms and solar parks across 12
4 states and we operate more than 4,600 megawatts of
5 clean, renewable generating capacity.

6 In my role, my capacity of the company, I
7 lead development activity for multiple wind projects
8 across the central region, primarily the MISO and SPP
9 regions. Among various aspects that I manage in the
10 development process is the projects generation
11 interconnection studies and ultimately working through
12 the interconnection agreements with the appropriate ISO.

13 I hope to bring to the panel a practical
14 generation interconnection experience in both of those
15 footprints, having recently experienced ramifications of
16 interconnections study delays and how they affect the
17 project on the ground level. My objective is to help
18 the Commission work towards a solution that will allow
19 wind generators to interconnect in every ISO in a
20 timely, non-discriminatory manner. I'd like to thank
21 the Commission for holding this panel and this
22 conference and the opportunity to present our views.
23 Thank you.

24 MR. EGAN: Yes, my name is Dave Egan. I'm
25 the manager of interconnection projects for PJM. My

1 department interfaces directly with the interconnection
2 customers, transmission owners, internally our legal
3 staff as we do all of the agreements, as well as our
4 study staff. So we deal with both the technical side,
5 as well as the legal side, as well as all of the project
6 management issues. From a transparency perspective, PJM
7 posts loads of market and operational data, our planning
8 models are available as are our reports and agreements.

9 One of the issues we have and I believe in
10 the first discussion that was brought up is there are a
11 lot of entrants into a queue. Some are savvy and some
12 are not. So having a lot of data available can be a
13 challenge for a new entrant because they're not aware of
14 where to go on a website, so PJM is always trying to
15 improve access to data too. So just having data is not
16 necessarily the answer, also having access to it, and we
17 do a lot of time, my staff, talking to customers to
18 guide them, to show them what's available.

19 Regarding backlog, in the first session
20 Mr. Naumann mentioned communication, we're finding that
21 to be key to reducing our backlog. My department, we go
22 out and try to meet annually with all of the
23 transmission owners. We have new staff just from
24 turnover, as well as just showing them what our process
25 is, what we expect from them, and then talking about

1 their issues of timing.

2 The first 30 days of a study we do our
3 analysis. What does it look like when they receive it
4 and how quickly are they able to turn it around? We
5 show them our needs at the end to be able to potentially
6 restudy, so if they provide us with a result that
7 doesn't solve the issue, we get into potentially
8 looping, and that can result in the delay. So we've
9 been better at communicating that.

10 The other thing Mr. Angell -- is that how
11 you pronounce your name? -- Mr. Angell brought up the
12 issue of interconnection requests being deficient, and
13 it was also brought up in the first -- we have a
14 stakeholder process right now at PJM trying to be very
15 strong on those rules.

16 Finally, on the delay causes it was also
17 brought up in the first, we see a lot of equipment
18 changes with new technology. The customer enters the
19 queue, by the time they get to their study there have
20 been large changes in the technology that require
21 restudies.

22 MR. HENDRIX: Charles Hendrix, manager of
23 generator interconnection studies with Southwest Power
24 Pool. My group administers the interconnection
25 procedures from accepting new requests through the

1 interconnection agreement. I appreciate the opportunity
2 to participate in this conference.

3 SPP's, our interconnection process,
4 functions pretty effectively since our last queue reform
5 in 2013. Our first cluster in that queue reform started
6 about 18 months ago, we had one outstanding request
7 within the interconnection agreement. The second study
8 that started 12 months ago, we had three requests that
9 are in facility restudy. Both of these clusters start
10 out with 7,200 and 5,200 megawatts of wind and oil
11 generation respectively. Furthermore, this has been
12 achieved in light of significant growth of wind in our
13 region. Through these processes, through our transition
14 to a energy market and our consolidated balancing
15 authority, and regional planning process, SPP has now
16 installed over 12,000 megawatts of wind.

17 However, despite the successes SPP has
18 experienced, the continued interest in wind has resulted
19 in obstacles to the efficiency of the execution of the
20 process. The volume of requests just continues to grow
21 and our last cluster from last September we had 11,000
22 megawatts of generation coming in one cluster. That
23 cluster that all went through one impact study, 7,700
24 megawatts went into the facility study in that one
25 cluster. So we're thinking the obstacles to go into the

1 facility study are not quite high enough. This past
2 study window that closed we had 11,000 megawatts of
3 generation come in. So now we've got 19,000 megawatts
4 of generation that are pending, that we really are in a
5 pickle to determine how to analyze that.

6 With the minimum loads that SPP sees and
7 with the wind operating at minimum loads, we are very
8 concerned about our wind penetration levels. Minimum
9 loads at SPP are about 20 gigawatts. So we're looking
10 at clusters of 20 gigawatts. Thank you.

11 MR. OYE: Good morning. My name is Randy
12 Oye. I'm a transmission access analyst for Xcel Energy
13 working on generator interconnection issues, and also
14 the chairman of the MISO interconnection process task
15 force. Xcel energy is a facility holding company
16 composed of four subsidiaries with operations in MISO,
17 SPP, and the western interconnection. Xcel Energy
18 participates in generator interconnection activities in
19 all three regions. MISO and SPP, Xcel Energy functions
20 as a transmission owner with the RTO acting as the
21 transmission provider. On the Public Service Company in
22 Colorado system in the western interconnection, Xcel
23 Energy functions as the transmission provider. Xcel
24 Energy is also an interconnection customer in all
25 regions.

1 Xcel Energy agrees that generation
2 interconnection queue reforms are necessary but does not
3 support a standardized approach across all regions and
4 transmission providers. Xcel Energy believes that the
5 stakeholder process in each region is the best venue for
6 reform. Xcel Energy urges the Commission to take timely
7 action to implement reforms, especially in the MISO
8 region, and believes that MISO's recent queue filing
9 which the Commission rejected without prejudice included
10 a number of improvements that would greatly enhance
11 MISO's generation interconnection process. The
12 improvements should include adding multiple scheduled
13 restudies with off-ramps to allow interconnection
14 customers to assess the viability of their projects.
15 Xcel Energy also believes creating milestone payments
16 structured to reward projects who select the most
17 cost-effective locations with the best transmission are
18 needed. Tying milestones to the cost of the
19 transmission network upgrades identified in system
20 impact studies could accomplish this. Thank you again
21 for allowing me to participate in the conference.

22 MR. RUTTY: Good morning. My name is Steve
23 Rutty. I'm the director of grid assets at California
24 ISO. One of my duties is to oversee the generation
25 interconnection process for the ISO. California ISO

1 appreciates the opportunity to participate in this
2 proceeding and in this conference. The ISO and
3 stakeholders have greatly benefited from the mutual
4 flexibility that the Commission has afforded us, and we
5 encourage FERC to continue down that path.

6 In 2008 when the ISO made a big move to
7 cluster studies, we have studied over 800 projects for
8 over 120,000 megawatts, and this is for a system that
9 has a peak load of about 50,000 megawatts. Most
10 recently we've disclosed our cluster 9 window that had
11 125 projects for another 25,000 megawatts. But under
12 the recent flexibility you've afforded us, our
13 stakeholders and California ISO have been able to
14 develop a process that allows us to run through 100
15 projects in a year, and aligns very well with our
16 transmission planning process and where we developed the
17 appropriate transmission for reliability economic and
18 policy needs: As Commissioner LaFleur mentioned
19 earlier, it aligns well with the distribution owners'
20 studies that they do for their distribution-connected
21 assets; it provides our interconnection customers with
22 fixed and anticipated annual studies and schedules, and
23 the annual costs for those studies as well, and it has
24 no restudies; and it provides cost certainty for network
25 upgrades to alert the interconnection customers very

1 early in the process.

2 The ISO continually works with the
3 stakeholders to identify enhancements to the process, as
4 you're probably well-aware of our annual interconnection
5 process improvement efforts. So with that, the ISO
6 respectfully requests the Commission continue to ensure
7 each region maintains the flexibility to adopt
8 interconnection procedures that fit their needs.

9 MR. ZADLO: Good morning. My name is Kris
10 Zadlo. I'm a senior vice president at Invenergy. Let
11 me start by saying that Invenergy supports the AWEA's
12 petition. The interconnection process continues to
13 impose significant barriers to generation development,
14 in some case delays of up to six to seven years.
15 Generic reforms are necessary to overcome these
16 barriers, RTOs and utilities should be required to show
17 that they have adequate resources available to
18 accomplish their obligations, and they should be
19 required to clearly enumerate study assumptions up front
20 before commencing on the studies.

21 TO should be required to abide by firm
22 deadlines or to state in writing why they cannot.
23 Meaningful Commission oversight, along with timely and
24 expedited dispute resolution mechanism, must be built
25 into the process. Greater Commission involvement in the

1 RTO interconnection process is sorely needed. Each time
2 an RTO deviates from a generic reform or
3 Commission-approved best practice, the RTO should be
4 required to file a notice of untimeliness or
5 noncompliance to explain these deviations. The
6 Commission should review these reports where appropriate
7 and investigate them.

8 Just as the market monitor and the
9 Commission enforcement staff scrutinizes outlier bids,
10 they should also scrutinize outlier interconnection
11 practices. The Commission should also require each RTO
12 to establish an ombudsman with direct access to
13 designated FERC staff to provide a venue for timely
14 relief when customers are at an impact or have a dispute
15 about matters affecting studies. These measures should
16 not prove unduly burdensome to any RTO that's doing
17 their job, because if it is no reports will be required
18 or calls to ombudsman necessary. Thank you for this
19 opportunity to speak today and I look forward to the Q
20 and A.

21 MR. DOBBINS: All right. Thank you again to
22 all of your participation and for your opening
23 statements and remarks. FERC staff will now begin
24 asking questions. Please limit your responses to around
25 a minute so that other panelists have time to speak.

1 And once again we apologize in advance if we aren't able
2 to hear from everyone at the table on every topic.
3 We'll start off with a question of -- talking about time
4 frame for studies. Are the completion time frames and
5 the pro forma LGIP and regional tariffs -- sorry, are
6 the completion time frames of the pro forma tariff and
7 regional tariff reasonable in regards to the amount of
8 time provided for completing an interconnection study?
9 And we'll start on the left and move down towards on the
10 right.

11 MR. ANGELL: Yes.

12 (Laughter.)

13 MS. AYERS-BRASHER: I can't comment to
14 whether the RTOs and TOs feel like they have enough
15 time, although I think we just heard from one that they
16 do. However, following those timelines and the
17 documentation of those, then we can plan with those, so
18 it goes both ways. And we have those laid out, we plan
19 based on those. So if they need to be different, we
20 need to know what those are.

21 MR. BOHACH: Along those lines, I'm speaking
22 for the time to put a study together, but from the
23 operator. And knowing what -- those timelines and being
24 able to plan around those for a project development,
25 those are sufficient timelines if we're able to adhere

1 and bank on those timelines.

2 MR. EGAN: At PJM we have timelines for both
3 large gen and small gen. And the issue we run into and
4 I think might be part of some of the issues the
5 generators have, in 2008 and '12 we've had reforms
6 through the stakeholder process where, for example, the
7 small generator said "We don't like the but-for cost."
8 If you look at a distribution circuit and three projects
9 ahead of us use up the existing overhead on that, we end
10 up the fourth project picks up the overall cost. So
11 they requested for under \$5 million upgrades to have
12 those socialized within the queue so everybody who
13 contributes to the overload pays for it.

14 The problem with that is now you have to wait for
15 the queue to close to be able to study everyone. So it
16 actually -- where before, the smaller generators could
17 have been moved along quicker, because if we analyzed it
18 and saw there was overhead, we could give you your
19 agreement and move you along. Now you're bundled
20 together. So it's a clash of cost sharing versus
21 timeliness that I see right now at least on the smaller
22 distributed generators.

23 MR. HENDRIX: At SPP, we had a number of
24 stakeholders processes where we decided instead of
25 timelines ordering the impact study, we also put in

1 increased milestones to get into the impact studies so
2 we were compressing time frames and we would have fewer
3 projects in the studies. As it turned out, I just
4 mentioned the studies have doubled and tripled in size,
5 so we're now finding that the timelines that we have are
6 very difficult to meet.

7 MR. OYE: Xcel Energy is comfortable in the
8 timelines to complete the interconnection studies. I
9 guess issues that have come up is when they start.
10 Lately, they've been delayed quite a bit, and that is an
11 issue. And as Charles said, there's a lot of projects
12 in the queues so they take a lot longer to complete
13 because of the restudies and others. So that's it.
14 Thanks.

15 MR. RUTTY: So at the California ISO the
16 queue cluster process takes about two years to get
17 through the study process, that's the phase 1 and phase
18 2. There are a couple of faster options if the
19 generator can show they have a demonstrated viable need
20 to move quicker and they are determined to be
21 independent from other projects that would be sharing
22 their cost. But the cluster side does take about two
23 years. It is fully integrated with our transmission
24 planning process. The timelines are in our tariff, we
25 can't miss them, and so far we've been able to meet all

1 the timelines. We don't have a study backlog. The
2 tariff requires that -- the transmission owners to meet
3 tight deadlines as well. So, so far so good. It
4 doesn't mean things won't change.

5 The deadlines that we have in there also
6 provide the interconnection customer time between
7 studies to make decisions as to whether they want to
8 move forward and how they're going to finance their
9 project, if they're going to get a PPA in time and so
10 forth, a power purchase agreement. And so the study has
11 that built into it as well, the whole -- the entire
12 process. So it's a give-and-take with the customers to
13 make sure that we have time to provide them a study that
14 gives them what they need to move forward, and that they
15 also provide financial security along the way to make
16 sure they're in the game as well. So --

17 MR. ZADLO: The problem is not the
18 timelines, the problem is the lack of rigor going
19 through the process. I'm going to give a shout-out to
20 Mr. Hendrix. When we enter the queue in SPP, we're
21 reasonably assured that within a year and a half to two
22 years we're going to end up with an interconnection
23 agreement. That can't be said with other ISOs. Cal ISO
24 also meets their timelines. Can't say I'm happy with
25 the length of their time, but at least after two years I

1 know I'm going to get an interconnection agreement. I
2 can't say that for other jurisdictions.

3 This is 2016, folks, this isn't 50 years ago
4 where engineers were doing power flows on punch cards
5 and using slide rulers. We have phenomenal models at
6 our disposition here where you can model the whole
7 entire eastern interconnection, have 100,000
8 contingencies analyzed in under a couple of minutes. So
9 the RTOs do a phenomenal job managing their markets, but
10 on the flip side, on the interconnection process, I
11 think there needs to be a higher standard there.

12 MR. DOBBINS: And taking into account the
13 comments just made by Mr. Ruttty and Zadlo about the
14 CAISO process and the SPP process, here's a question for
15 the transmission providers: How often are studies
16 completed within the time frame establishing the tariff?
17 It seems like at ISO and -- I guess and SPP, pretty
18 often. And when these completion rates vary, what
19 generally accounts for this variance?

20 MR. ANGELL: Well, with Idaho Power, again
21 as I mentioned earlier on, the variance, we actually
22 don't start the clock until all the data comes in. And
23 once we start that clock, if they do come in -- well,
24 all the data comes in and is correct. And then we start
25 the clock. If they go and change the technology that

1 they're using, then obviously we start the clock over.
2 So we always meet our time, and it's dependent upon the
3 customer providing the data as far as what that overall
4 time will be from when they first come in.

5 MR. EGAN: At PJM the issues that you get
6 into, and discussed earlier and mentioned earlier, the
7 customer is accountable to providing the data timely.
8 Data holdups right now, we end up -- if you look up at
9 the 90-day feasibility study, window for our tariff,
10 almost the whole first month is wasted in the process of
11 getting data in and holding scoping meetings. We have
12 some queue reform that we're getting ready to propose,
13 but that is not in place right now. So that's one
14 issue. As far as going to get the studies out, we still
15 are able to get the feasibility studies out on time.
16 We've improved greatly in the last I would say three to
17 five years on that. Impact studies are generally out on
18 time. The problem you get into when you issue, for
19 example, an impact study, and you're sending them out in
20 the cluster format, is you're going to get now people
21 who see the results and withdraw, so you're almost
22 automatically into some form of model cleanup and
23 central retools as far as lining up where the
24 obligations to build network upgrades are going to
25 follow but-for issues. So that's one of the biggest

1 problems.

2 I agree we have great modeling, but the
3 problem is you also have business decisions that have to
4 be made and reaccounted for after they're made. And
5 they are in queuing order, so --

6 MR. HENDRIX: In SPP, it can take over a
7 month to six weeks to validate all of the generator
8 data. And we have been pretty rigorous in withdrawing
9 requests that haven't met those timelines once we've
10 been able to validate that. However, the way our tariff
11 is and our studies, timeline starts as soon as the
12 window closes, so that's really counting against us
13 while we're evaluating all that data. Despite that, we
14 have a pretty good percentage of completing the impact
15 studies on time. SPP is pretty -- we have a large
16 region, the western part of the region we kind of study
17 separately. That's where a lot of -- where wind is,
18 that's where the transmission system is not near as
19 robust. So what happens is that -- and there seems to
20 trail, we will have more restudies there with
21 withdrawals, and so that -- we will that area is
22 generally behind maybe 30 days to 60 days. With the
23 upcoming clusters, we've actually put a hold on this
24 latest study so we can get a better handle on the last
25 study that had 7,700 megawatts going into facility

1 studies. So the speculative requests that appear to
2 continue going forward even in the facility study are
3 going to cause greater delays going forward.

4 MR. DOBBINS: Feel free to skip this
5 question. Since you answered this in the last -- did
6 anyone else want to speak?

7 MR. ANGELL: I just had one more comment.
8 And so as a fairly small utility, we augment our staff
9 with consultants in order to meet the time frames that
10 are in the tariff. And so augmentation is always
11 required.

12 MR. DOBBINS: Thank you. We have a
13 follow-up question.

14 MR. LUONG: Yes, I had a question regarding
15 the input data. Is there any way you contain the -- how
16 to improve that between the transmission provider and
17 transmission customer, along the way help to -- help out
18 the good data, get the thing right away and meet -- up
19 front? And then we hear about a lot more new technology
20 from modeling. Is there any way that in the industry
21 can work together with the manufacturing, try to come up
22 a lot of new model and then onlook -- go with a vendor
23 for the tool so you can shut down the issue about your
24 data at the beginning of the input --

25 MR. ANGELL: So in the western system, WECC

1 has the nearest models that are approved and defined.
2 So that information is provided to the interconnection
3 customers, and then it's up to them to either choose to
4 use a generic model or provide the full data with regard
5 to the exact equipment that they're supplying.

6 MR. EGAN: Regarding your issue improving
7 the process, we are trying to make tools so that it's
8 very clear what the customer needs to provide coming in,
9 and tightening up the rules so that if they do put in
10 bad data or don't provide the data, that they really
11 don't get to participate in the queue or hold the queue
12 up.

13 MR. HENDRIX: In SPP, similarly we've been
14 working with customers the front end, and we've got a
15 checklist. Many of our customers who have been through
16 the process many, many times. So they're well-aware of
17 what's needed, yet sometimes they still don't provide
18 everything. It's just when our window closes, let's get
19 everything in there that we can, and hopefully let's get
20 things sorted out. So to an extent, that's an obstacle.

21 MR. EGAN: I'll add one other point here. A
22 comment on working with the manufacturers: Some of that
23 actually comes from the customers, too, as far as if
24 they keep updating their models, they need to be
25 providing models that the transmission providers can use

1 to study. They're the ones that would have the
2 financial leverage to get the manufacturers to provide
3 that, so --

4 MR. DOBBINS: How much has this been an
5 issue, not getting the technical information from the
6 manufacturer?

7 MR. HENDRIX: It's very difficult when
8 you're doing the dynamic studies to get the dynamic
9 models. And the issue there, that goes back to what I
10 was saying about the speed at which some of the newer
11 technologies are being updated all the time, the
12 manufacturers have to also be in parallel updating their
13 models, and that's been an issue.

14 MR. ANGELL: And I might add to that as
15 well. Sometimes it has to do with these new designs,
16 confidentiality around those designs, and the
17 manufacturers have definite concerns there and will
18 withhold information, or try to.

19 MR. ZADLO: I just want to provide some
20 color to this topic. The interconnection process takes
21 way too long. And we know today, if I submit a request
22 today, I know by the time I get through the process the
23 equipment that I submitted my request with is obsolete,
24 it will be no longer in production. So you all need to
25 keep that in context, and that's why those material

1 modification requests are so needed, because technology
2 is evolving at a rapid pace. So there needs to be
3 flexibility and you need to consider that, that this
4 isn't a stagnant "Okay, I submit this and this is what
5 I'm going to eventually interconnect."

6 MR. DOBBINS: Is there anything in terms of
7 information and transparency that can be done or changes
8 that could help that process if there's an issue of when
9 I start the process, here's what I'm presenting
10 throughout the process, that they may be changing some
11 part of it is information flow, part of it is just
12 timing, as you get updated and -- yes or no? What can
13 be done to improve that process so that everyone is
14 aware as soon as possible about any changes in a project
15 and other projects, what sort of helps with that?

16 MR. ZADLO: So what I will say is I think
17 the bar for restudies is set very low. I think a lot of
18 these restudies are unnecessarily performed or they can
19 be performed in parallel with the queue. And I mean
20 unnecessary, there was an instance where we had to move
21 the substation 500 feet, okay. The transmission owners
22 said "We got to re-perform all the studies."

23 Good engineering judgment would say that's
24 not necessary. With the situation with the equipment
25 changing, rarely has that caused or flagged additional

1 upgrades, all right. So if that's the case, let's have
2 a separate group that performs re-studies on change of
3 equipment in parallel while the interconnection analyses
4 are being performed; that's another way to deal with it.
5 Goes back to my original comment that there's not enough
6 resources studying interconnection. The same individual
7 who is studying the interconnection request is the same
8 individual that is doing the restudy.

9 MR. DOBBINS: Would anyone else like to
10 comment on this before we move on? Okay. Sorry. I
11 thought I heard a click of the microphone. In the event
12 that there are delays in the study process, how are
13 those reported to interconnection customers?

14 MR. ANGELL: So the delays in the study
15 process are recorded by a phone call, e-mail, and of
16 course hard copy letter. And with that, we also
17 identify the cause for the delay and essentially the
18 party that has the action item to clear that delay,
19 whether it's either the customer themselves or the
20 utility and a timeline for that.

21 MR. DOBBINS: Would that include information
22 on other projects, maybe that they're somehow involved?

23 MR. ANGELL: Yeah, sure. If it's a restudy
24 effort, yeah, project in the queue, senior project
25 dropped out, that is correct.

1 MR. DOBBINS: I'm going to have the same
2 question for everyone else. How are they reported in
3 the clauses?

4 MS. AYERS-BRASHER: I think our experience
5 has been that some places give you a reason why, some
6 don't. Sometimes it's a phone call and sometimes it's
7 an e-mail. You might hear about it. Sometimes you hear
8 about the delay before the study's even started, and
9 sometimes those have reasons like the project -- the
10 queue ahead of us and sometimes they don't. So there's
11 no consistency. We don't have -- and it may be
12 consistent within a region, but it's not consistent
13 across. We don't always know what's going on what the
14 causes of those delays are, and it makes it difficult,
15 again, to figure out what we're doing on our side and
16 where we need to slow down or what we need to do.

17 MR. BOHACH: The inconsistencies, to go on
18 what Jennifer said, the issue regarding the
19 notifications, there's lots of venues depending on which
20 ISO we're operating in. Websites are obviously a tool.
21 We'll get letters, stakeholder or ad hoc groups to meet
22 with or discuss delays. But those will often ebb and
23 flow through the process. Frankly, what we sometimes
24 find is just our inquisition with the ISO, that is often
25 where we find it on the one-off e-mail or phone call to

1 discuss a particular study or group project on that, or
2 hearing from potentially another person in that group or
3 something. So consistency I would say is one thing
4 that's lacking in that notification.

5 MR. EGAN: At PJM we have for each
6 transmission owner a project manager so the customer
7 will have a direct line with someone on my staff to be
8 able to contact. We issue e-mail notification if the
9 study's going to be delayed. Part of the process, when
10 you have a tight process, for example, 90 days to do a
11 feasibility study and 30 days get eaten up upfront, so
12 you're looking at about a 60-day study, I think some of
13 the issues the customers have is, from what I've heard
14 from them when they call me to complain about it, is
15 that we're notifying them just before the study's due.
16 That's about when we're hearing from the transmission
17 owner that there's an issue or they're going to be
18 behind.

19 So I think that's part of the rub, is that
20 you're finding out late in the process, but that's just
21 how the process is set up right now. It's very tight
22 time so therefore you're at the end before you know that
23 you're going to be delayed.

24 MR. HENDRIX: We'll send out e-mails to the
25 customer as - generally as soon as we know and as soon

1 as we're reasonably sure we're going to be late, we'll
2 let them know. And sometimes that's early and sometimes
3 that's late in the process.

4 MR. OYE: Our experience is usually it's
5 through e-mails, we'll receive an e-mail, and then
6 stakeholder meetings. So there's usually updates on
7 what's going on. So those are the primary ones.

8 MR. RUTTY: At the California ISO each
9 interconnection customer has an interconnection
10 specialist assigned to them, and they communicate all of
11 the schedules for the study process, all the due dates
12 for financial security, for postings, to provide
13 additional information after phase 1 and before phase 2
14 to accommodate their needs for any material
15 modifications that they may have. So we have a single
16 individual for each interconnection customer on that.
17 And as far as communications, it could be a variety of
18 things. It could be a letter with receipt required or
19 it could be an e-mail or a phone call.

20 MR. ZADLO: It varies across the board.
21 Some transmission owners, it's a black hole, you get no
22 feedback. Typically, it's just an e-mail with little
23 explanation as to why the delay is occurring. What's
24 more interesting is when you do get an explanation as to
25 the why the delay is occurring and usually it has to do

1 with that resource that's studying your process that is
2 being diverted to something else. And that's when it
3 gets really interesting because you clearly get a view
4 that the interconnection process is not a priority to
5 that transmission planner. We've gotten explanations
6 that, "Well, we have to do the transmission expansion
7 plan by the end of the year, so your folks studying your
8 requests has to now work on the transmission expansion
9 plan," which always gets done on time with every RTO.
10 There's hundreds of different scenarios and upgrades
11 being studied, yet when it comes to one generation
12 interconnection request it's difficult for them to
13 process that in a timely fashion.

14 MR. OYE: Just kind of general on this
15 topic. The delays aren't -- there's a lot of reasons
16 for the studies being delayed. The transmission
17 provider, getting the studies done and having enough
18 people to do it, you could maybe say, "There's something
19 to that but they could do better." But our experience
20 is there's -- especially in our area, Minnesota, North
21 Dakota, South Dakota, it's a very good wind area, and we
22 have tens of thousands of projects coming into the
23 queue. And there really isn't the market for that many.

24 So the projects come into the queue, they're
25 studied, a lot of them drop out. And they tend to drop

1 out at different times in the process, so they're not
2 all dropping out at once so it's not just one restudy.
3 The August 2012 cycle in MISO, there was six restudies,
4 and that was because projects just drop out at certain
5 stages.

6 And so really there's reasons for the delays
7 and why things are behind, and a lot of it has to do
8 with just, my opinion, our opinion, the company opinion,
9 there's -- the financial milestones are not appropriate,
10 MISO, I've been involved in three queue reforms and
11 every time we've done it we make it a little harder.
12 The first time we said if you have turbines, and then
13 everybody managed to get turbines. That was a
14 milestone. The second one we made it about money, and
15 again, still there was a lot of projects coming in. And
16 we keep upping it, and it usually works for a little
17 while and it works for a couple cycles, but it doesn't
18 necessarily solve the problem.

19 So our opinion is really what MISO came up
20 with recently, it gives you three shots to get through.
21 You do an initial study as a cluster, which kind of
22 gives you a better idea of what your upgrades are; and
23 then you have a choice to move forward or not. And we
24 think those milestones, what's important is they're tied
25 to transmission upgrades. If you're a 100-megawatt

1 project and you've got 10 million or five million
2 transmission upgrades, your milestone should be a lot
3 lower than if you're a 100-megawatt project, 50 million
4 upgrades. So we really think that there's some
5 structural things that could be fixed in the
6 interconnection process that would help with the
7 restudies, would get some of the things, the timeliness
8 and completion done, and better approval. Thank you.

9 MR. DOBBINS: I think that's a good time for
10 -- FERC Staff has a few question on restudy, so I think
11 we'll jump in on that.

12 MS. GRAF: Thanks, Tony.

13 As we've seen restudies, the problem of
14 them, the stability of the queue is an emerging theme at
15 this tech conference. So we were wondering, especially
16 for the transmission providers, how often do you perform
17 restudies or is there a set procedure for how often you
18 do restudies? And for developers and those that operate
19 within different regions, whether you see variations and
20 how restudies are performed or how commonly they're
21 performed?

22 MR. ANGELL: So first I'd address -- so
23 Idaho Power did operate a cluster many years ago, and in
24 that cluster we did have multiple restudies that
25 occurred at that time. Since then we've tended to avoid

1 a clustering of studies. So the restudies for a group
2 have definitely diminished relative to that. However,
3 for, again, those entering the queue and then dropping
4 out, only 20-percent conversion rate, there are
5 restudies, but with regard to our system and our
6 staffability, the restudies are done within the time
7 frame so it's not extending the project's time.

8 MR. EGAN: PJM, our tariff defines when we
9 do the restudies, so if you have a withdrawal the IROT
10 has to restudy everybody else after it to find out if
11 the obligations to build the network upgrades shifts.
12 The issue with that is, when you issue a study you got
13 to tell a customer, right now you may actually fall
14 through our cost allocation rules and not have a cost
15 allocation. But if you're after someone who has caused
16 it, you'd ultimately have to include it in there because
17 if someone withdraws the stack-up where the hundred
18 percent threshold crosses may fall on that customer. So
19 any time you have that you have to restudy to make sure
20 the but-for costs are being applied to the right
21 customer. So it's a lot of work to do restudies, but
22 it's a required work to do for analysis.

23 MR. HENDRIX: Restudies will trigger higher
24 withdrawal, we know we're going to have restudies after
25 every impact study that we could, and our new procedures

1 pretty much have that built into it. We're pretty much
2 agreed again to have another restudy, once the requests
3 are going into interconnection agreement. But even
4 after that, there's really no set time of when you know
5 somebody is going to withdraw, it just happens any time
6 after an interconnection agreement that you can
7 terminate that agreement. And so you just have
8 continuing restudies, we've had one cluster with seven
9 or eight restudies due to withdrawals. At some point in
10 time you can have a withdrawal and determine that this
11 is an area that we don't have to restudy. But in our
12 western footprint where more wind is, there can be
13 several restudies.

14 MR. OYE: If it's okay for me to speak to
15 MISO, MISO's tariff has three conditions where restudies
16 will be performed.

17 MR. RUTTY: So the California ISO, we have a
18 process, it's a two-phase study process. Phase one
19 study is done the first year where we identify upgrades
20 that are going to be needed for that clustered route.
21 Each interconnection customer within that study receives
22 a cost cap, which throughout the rest of the study
23 process that will be the maximum cost responsibility
24 they will have. It helps them to decide whether they're
25 going to move forward or withdraw.

1 When we go into the phase 2 study, we go
2 into a much more detailed study. The study now has
3 already taken into account for the withdrawals of the
4 phase 1, and it's just the interconnection customers
5 that moved on into phase 2.

6 Now, they'll get a new cost allocation, but
7 if it's higher than the phase 1 they're still protected
8 by the cap that got in the phase 1 study. This has
9 helped a lot in reducing the need for restudies and
10 makes decisions to move forward, post-financial
11 security, and move on. But if we do have additional
12 withdrawals after the phase 2 and we do an annual
13 reassessment where we look at who's left in the entire
14 queue, all the clusters together, and identify where,
15 based on withdrawals or projects, where network upgrades
16 can be removed -- and usually it's the case that upgrade
17 networks are removed from the clusters and from an
18 interconnection customer so that their costs continually
19 go down -- they get a new what we call "cost
20 responsibility." Ultimately, they only pay for what
21 they need at the end.

22 So through this process, it's really
23 eliminated the need for a restudy; we're allowed to
24 continually move the clusters through the process and
25 reassess them annually without a need for what we call a

1 "complete restudy" that would completely throw an IC's
2 financial book out the window. That consistency and
3 security that they have from very early in our study
4 process.

5 MR. ZADLO: If I'm batting .300, I'm not a
6 bad guy, I'd most likely go to the All Star game. So
7 there needs to be an understanding of the development
8 process. And when you build something in many
9 jurisdictions, okay, your special use permit is only
10 good for two years, all right. So I've constantly
11 playing this game of trying to marry up my construction
12 permit with the timing of the interconnection process.
13 And unfortunately it's the interconnection process
14 that's along the items in developing power plans, all
15 right. So I can't move forward with the permitting
16 process until I have line of sight on my interconnect,
17 make sure I can get that project across the line.
18 That's just one of the many things that I'm weighing
19 here. Right? So just because people drop out, it isn't
20 because they have bad intent. Why would have spend
21 hundreds of thousands of dollars on an interconnection
22 request just to drop out? Right? So I want you guys to
23 keep that in context.

24 The other thing you all should keep in
25 context is that there are RTOs and ISOs out there that

1 have phenomenal dropout rates and are able to deal with
2 it. PJM and SPP, they have large dropout rates, and
3 they're able to do it because they know that during the
4 different stages there's a certain dropout rate, and
5 they do a probabilistic analysis knowing that, okay,
6 these folks in the feasibility study only 70 percent --
7 or Dave can tell me -- 80 percent will go forward. Once
8 you get to the system impact study, 50 percent go
9 forward, so forth and so forth. So they're able to deal
10 with the issue.

11 MS. GRAF: Some of you mentioned some of the
12 tariff triggers for restudy. For developers, do you
13 find that the triggers for restudy and the procedures or
14 the tariff are sufficiently clear? And do you see
15 variances between the regions?

16 MR. BOHACH: So we do see variances between
17 the regions, the difference between RTOs, ISOs and all
18 that. As Chris had mentioned, for example operating in
19 SPP, we know when those are going to occur, we can plan
20 for those and make those good, sound business
21 discussions based on that, knowing whether we'll see
22 restudies. So that's a good case scenario in our
23 experience operating in SPP with the tariffs. Those
24 restudies get drawn out and then you have -- you lose
25 that cost certainty, which now a project that maybe

1 didn't affect my project drops out and there's something
2 that now attaches to my project now, which potentially
3 calls into question the viability of that project. So
4 we do see the variance, some good and some bad.

5 MS. AYERS-BRASHER: Yeah, we see the
6 variance and it is somewhat defined in the tariff, the
7 higher queue project drops out, we see that, we
8 understand that. But I think there's got to be ways to
9 either have the restudies perform quicker or ways to
10 accumulate the data that allows to have a quicker
11 understanding. I don't know if a full restudy is
12 necessary, possibly what California ISO does, that
13 limits those restudies. There are options and ways and
14 we just need to find those and make them work. And they
15 may be slightly different for each region, but we need
16 to find what those are and fix it. Because those
17 restudies do make it difficult. Earlier information
18 could make things -- if people had a little bit more
19 information in the feasibility study, maybe they'd drop
20 out sooner. So that when you get into those longer
21 studies that take more time and also cost us more to
22 complete, there's a little bit more uncertainty at that
23 time as well.

24 MR. DOBBINS: We have a question from
25 Commissioner LaFleur.

1 COMMISSIONER LaFLEUR: Thank you.

2 Listening to this conversation, I'm hearing
3 a couple high-level messages that are in conflict or in
4 tension with each other at least. One is that there's
5 considerable disparity among the regions in their
6 ability to work through their queues and meet their
7 timelines, the way the processes work. And the second
8 is, in the opening comments I heard a few pleas for
9 regional flexibility and leading the regions in
10 different ways, which seems to be a little bit in
11 tension with having best practices spread through the
12 generator interconnection or otherwise. In the interest
13 of stability, you want regional flexibility, if you
14 could expand on why you think that's important and where
15 you think we should kind of -- how do you think we
16 should look at this tension, because it's always a
17 tension in so many things, in posing the best way to do
18 it or letting people do it differently? And we've heard
19 a lot of different things. Thank you.

20 MR. DOBBINS: We'll begin on the left and
21 move down the panel.

22 MR. ANGELL: For one of the first reasons
23 for regional flexibility in the western system is not a
24 full market throughout, so there's a starting point.
25 Additionally, having worked in a lot of stakeholder

1 processes at the local level with Idaho Power itself, at
2 the regional level through the Pacific Northwest, we
3 find that stakeholders' involvement locally allows us to
4 engage with those individuals and make reforms to the
5 benefit of -- where we can essentially compromise and
6 come up with the best solution. But I do understand
7 best practices throughout industry are always important
8 to take throughout. The question is what's the right
9 level of -- not heavy-handedness to enforce things --
10 but to allow it to grassroots grow.

11 MS. AYERS-BRASHER: Maybe just a quick
12 comment. While we feel there should be more
13 commonality, maybe across the board especially where
14 there's more markets, we understand there might be some
15 need for flexibility, but we would like to see a lot
16 more consistency.

17 MR. BOHACH: We're consistent with that view
18 as well. Commonality across would help on the operator
19 end.

20 MR. EGAN: I guess I would mirror David's
21 original comments, though, the issue with markets, how
22 the markets interface with regional areas makes that
23 somewhat difficult.

24 COMMISSIONER LaFLEUR: Even between
25 organized market areas, I can certainly see bilateral

1 market areas and RTOs having a different paradigm as
2 Mr. Egan said, even among the market areas.

3 MR. HENDRIX: The different states, as
4 mentioned earlier, have different appetites for
5 renewables. And SPP stakeholders have approved a lot of
6 regional transmission that's facilitated our queue
7 greatly. So that's one main regional difference. The
8 markets work differently as well, so I thought I'd bring
9 up what those regional differences are, are important.

10 MR. OYE: Our Colorado system, it's not a
11 market, it's one state and it's worked really well.
12 Whereas in MISO in our area, there's just huge amounts
13 of renewables, wind in the process. I don't think --
14 SPP is also in that same situation, but I think the East
15 Coast -- I don't think they have that kind of amount of
16 renewables. And in our area for every 5,000 megawatts
17 or 2,000 megawatts of PPAs or off-takers, we might get
18 20,000 megawatts of requests. So the market doesn't
19 support all the amounts of queues or prejudices in the
20 queues, so I think those areas should be handled just a
21 little differently than others, so regionally I guess is
22 the answer to your question.

23 MR. RUTTY: Yeah, I believe the ISO has a
24 similar view points to the panelists. We've were able
25 to create an interconnection process that's worked well

1 for us. The serial approach was just unworkable. And
2 so allowing us that flexibility to move forward with
3 solutions that worked well in California was key to
4 being successful. Now, that -- it's no hidden secret
5 that the ISO is looking at regionalization possibly in
6 the future, and this could change our game and we'll
7 have to be able to be very nimble on our feet to adapt
8 to that as more states may join in and move forward, so
9 just having the regional flexibility to allow us to
10 really listen to our stakeholders and provide a solution
11 is very key for this.

12 MR. ZADLO: I personally dislike the
13 deference that's given to the RTOs. Many times many of
14 our requests are, let's say, on the scenes where it's
15 unclear whose RTO or TOS reliability standards apply,
16 are we meeting this standard or that standard? So there
17 are issues when you start diverting from the standard
18 pro forma. The other issue is deference is okay, if
19 they're meeting their timelines, if they're not meeting
20 their timelines then they should be required to take on
21 best practices.

22 The last thing I will say is just because
23 something's been performed in the past doesn't mean
24 that's the best path moving forward. Again, there's
25 lots of regions where it's taken six to seven years, and

1 to say, "Well, this is our regional practice, this is
2 how we've done it for the last 50 years," well, if this
3 is how you've done it for the last 50 years and it takes
4 you six or seven years to get through the process, then
5 maybe it's time to change it.

6 COMMISSIONER LaFLEUR: Thank you.

7 MR. DOBBINS: Commissioner Clark?

8 COMMISSIONER CLARK: Thank you.

9 Just quick followup on the last question
10 because it's very similar to the question I had. And I
11 think this is mostly a commentary for a folks who are
12 going to be submitting comments to the Commission post
13 record.

14 I would really appreciate some focus on that
15 particular issue from those folks who are arguing for
16 lots of regional flexibility amongst the organized
17 markets. I guess the bilateral markets are different.
18 I think there's some reasons you could separate that
19 issue out. But with regards to the organized market, if
20 you could give me some examples of why different market
21 constructs really impact a process management issue --
22 which is how I see this -- that would be very helpful.
23 I understand from the purely market issues like one
24 region has a capacity market because we have certain
25 state regulatory regimes in that area and another region

1 doesn't, and on its face I could see why you would have
2 regional flexibility.

3 When it comes to just a process for doing
4 engineering studies for how different projects
5 interconnected with the grid, to me it just seems like
6 obvious on why a market-to-market difference would
7 dramatically impact that. So if you could give some
8 examples on why that's the case, that would be very
9 helpful.

10 I understand that there are regions in the
11 country that have -- my own region in the country where
12 there's tens of thousands of megawatts in the grid --
13 which is different from another region of the country.
14 But from a process standpoint, I'm not understanding
15 exactly why there has to be a great deal of flexibility
16 if there are indeed ways that we've found that you can
17 process that better than others. So if you can provide
18 examples to that, that would be helpful for me.

19 The question I have, it's come up in a few
20 different comments. It seems like one of the real
21 challenges, especially for regions of the country that
22 have a large amount of especially renewables that are
23 seeking to be interconnected is this kind of almost
24 Oklahoma land rush issue kind of issue that we've run
25 into for well over a decade now, which is you have lots

1 of developers who are out there trying to develop
2 projects -- and God bless them for trying to do it --
3 but we all know, realistically, not all of that can come
4 on to the line, there are going to be market issues why
5 you can't have that sort of thing.

6 And the gentleman from Xcel who's talking
7 about the threshold that's going on -- not to be
8 cold-hearted about it -- but is there anything wrong
9 with just as a means of trying to deal with that issue
10 to continue to ramp up those requirements? It might be
11 kind of Darwinian, but does it become something where if
12 there's that much wind power, for example that's trying
13 to get down to the queue and get through the
14 interconnection process, could you simply add to that
15 high bar to weed out projects that realistically don't
16 have a chance to getting on? And is there a way to do
17 that in a nondiscriminatory way so that you can clean up
18 the queue? And what would that bar look like, how high
19 does it have to be? Are there sort of -- I'll leave it
20 open. Are there outside-of-the-box ways we haven't
21 thought of to weed through the project so that in a
22 non-discriminatory way only the fittest do survive?

23 Go ahead.

24 MR. OYE: I'm not sure who you were asking.
25 We agree with that. And I think at MISO they recognized

1 that years ago and we just never set the bar high
2 enough. So yes. And there's been a lot of discussion
3 since MISO filed their queue reform, and there was a lot
4 of discussions on what the milestone should be. And
5 it's really hard to determine what is right.

6 But through discussions and working on it
7 with a lot of stakeholders, our opinion, my company's
8 opinion and some of the other stakeholders, that if you
9 tied it to the network upgrade -- and it's been
10 mentioned about models and somebody I think on the
11 earlier panel mentioned that you can get a model, you
12 can run studies, you can get an idea what your project
13 look like, but until it's run with all the other
14 clusters you really don't know.

15 So if you did the first cluster study and
16 you identified the cost of the network upgrades, and you
17 somehow tied the milestones for the next step that you
18 had to pay to go further to what your upgrades are, and
19 the logic behind that is, if you're in a spot and you
20 have 100 million in upgrades and you're a 200-megawatt
21 project, you probably should drop off. But if there's
22 no milestone payment, maybe you don't. Maybe you think,
23 "Well, I'm going to stay in but all these other guys are
24 going to drop out."

25 And we used this -- in my opening

1 statement we used the term "we do the good projects."
2 So if you set some threshold that you didn't have to pay
3 -- you pay your initial milestone to get in the process,
4 your next milestone you would not have to the pay more
5 if your network upgrades were under some threshold,
6 likely based on your size. So much \$100,000/megawatt,
7 if your network upgrades are below that you don't have
8 to pay more. But if your network upgrades are above
9 \$100,000/megawatt, you pay some percentage of that
10 amount. And as you step through it, we actually ran
11 some simulations on some of the MISO queue reforms and
12 we applied that criteria to projects.

13 And after we ran through it three times, a
14 lot of the projects didn't have any upgrades. And most
15 of the projects that survived -- again, you don't know
16 what the project is going to do -- it seemed like it
17 could work. And again, if you get to discriminating,
18 small developer in a bad spot, if he's got a lot of
19 network upgrades, we don't think that would be
20 discriminatory. So again, tying it to network upgrades
21 seems like the reasonable.

22 The other thing that I think you have to do
23 is I think you have to have firm deadlines and firm
24 timing, that somebody can't sit in the facility study so
25 the last point and kind of -- because I think projects,

1 there's an incentive to stay in as long as they can.
2 Everybody's trying to get a PPA or sell their projects,
3 so there's incentives to be there until the last moment.
4 So anyway, that's my thoughts.

5 COMMISSIONER CLARK: Thanks.

6 Anybody else who want to take a stab at
7 that?

8 MR. RUTTY: I'd like to take to respond to
9 that. The California ISO put in very high bars for
10 financial security. And with hundreds of projects
11 competing to be that five or six that actually complete
12 the whole process, even with a high bar we see a lot of
13 people putting down financial security and in the end
14 withdrawing. So that was a loss for them because they
15 lose some of their financial security if they drop out.

16 One of the things we did in this last big
17 change was to move the delivery network upgrades that
18 allowed a project to become deliverable and meet our RA
19 requirements, the resource adequacy requirements in
20 California, was to once they finished the pay-to study,
21 if they said, "Hey, I don't want to pay for any of these
22 upgrades, I'm only going to take what's available to
23 me," they actually compete for those based on milestones
24 they've met.

25 So putting in milestones such as do they

1 have financing, do they have a power purchase agreement,
2 do they have permitting, rank them up to be able to be
3 awarded the deliverability from the transmission network
4 and they came out of their transmission planning
5 process, that was a big part of integrating it.

6 Yes, having a high bar did get rid of
7 some, but it wasn't the whole solution, it was a
8 multiple of solutions. One was financial security; as
9 well as they needed to progress along as well to be able
10 to achieve the deliverability allocation at the end of
11 the process. And if they didn't, they could continue on
12 as an energy-only project or withdraw at that point.

13 But in California -- I know others are
14 seeing the same thing, I believe our dropout rate is 80
15 percent or more. It's very competitive out there; and
16 that's not a bad thing, but it's tough on the developers
17 when they realize they're one out of 10 that are going
18 to succeed.

19 MR. EGAN: The issue of every customer, the
20 speculative customer, every customer when they come to
21 me tells me how real their project is. So to say that
22 we can find a bar to get rid of a speculative project, I
23 don't think is possible, at least I'm not sure how you
24 would do that. The marketplace, I think, will clear
25 projects that aren't real. When they see a cost that's

1 not going to be economical they'll withdraw the project.

2 And I think it's tied together, as the issue
3 Kris mentioned, six- to seven-year project delays,
4 projects become coupled together. The longer you have
5 projects in your queue or backlog, the more they get
6 coupled together. In other words, you need the first
7 project to make a decision, the second project to know
8 what their costs are going to be. If you get a complex
9 project upfront that's drawing that out, that gets to be
10 very problematic for everyone else.

11 So working, and this was talked about in the
12 first session with communication, I'm finding that if we
13 can keep the transmission owners working, projects in
14 parallel, even if the TO thinks, "Well, that project
15 needs to make a decision first," still go ahead and
16 engineer all of it. We have the facilities studies.
17 And the one studies process we haven't mentioned today,
18 we talked about feasibility impact studies, the facility
19 study, the tariff really doesn't have a set deadline for
20 that. It says it should be completed in 180 days. And
21 the issue you get into is putting the planning
22 resources, generally once you get to the facility
23 studies phase, you're working with the engineers that
24 are working in the field. Feasibility impact studies
25 are generally desk-side studies.

1 So to get the transmission owners, even if
2 they don't have enough staff working in the field, to
3 augment their staff -- and I've heard others say they're
4 doing that -- to me, that's the big thing that has to
5 occur to get rid of these backlogs, allow people to make
6 their decisions on the economics, and then if you have
7 to restudy a restudy, but things will be moving along
8 faster because you've done all of the studies and know
9 what has to be done.

10 MR. HENDRIX: At SPP, I think our deposits
11 are pretty good. We still have too much room for those
12 to be refunded. At SPP, I mentioned we have a restudy
13 built in after the impact study. We're pretty much
14 giving the customers a free look after the impact study
15 to get all their deposits back. They can reduce the
16 size of their interconnection request; they can drop
17 network resource interconnection service; anything they
18 want to do after that impact study. But going into the
19 facility study, we require a higher deposit. But the
20 intent of serious projects going into the study, they go
21 and get that money back, but there are still avenues for
22 getting that money back, so we probably would like to
23 tighten that up so we only have viable projects going
24 into the facility study. The problem with tying it to
25 network upgrades is you may have -- it's like if a new

1 345 line gets built into the planning process and you're
2 the first customer to interconnect that 345, you may not
3 have a lot of network upgrade, doesn't mean you're not
4 clogging up later queue projects. Thanks.

5 COMMISSIONER CLARK: Did you have a comment?

6 MR. ZADLO: Yes. So what higher deposits do
7 is essentially limit throughput. If you look at the two
8 RTOs with the lowest deposit requirement going in, I
9 think it's PJM and ERCOT, and they have the highest
10 throughput as far as interconnection studies go.

11 COMMISSIONER CLARK: When you say
12 "throughput"?

13 MR. ZADLO: The amount of interconnection
14 studies processed, okay. So I think by raising the bar
15 -- when I say "bar" raising the deposit bar -- you're
16 not addressing the underlying issue which is lack of
17 expediency of the analysis. That's ultimately the issue
18 there that needs to be resolved. The second thing is
19 you raise it to high, you get into a discriminatory
20 situation where only the really big companies or the
21 vertically-integrated utilities in those footprints are
22 the only ones that can move forward.

23 Let's look at ERCOT for instance, with PJM
24 in the Marcellus Shale, they have low interconnections
25 amounts, right, but yet ERCOT over the last five-six

1 years interconnected over 10,000 megawatts of wind.

2 Now, it's buyer beware because a lot of
3 those interconnection requests in those facilities that
4 got built were in the panhandle or behind the panhandle
5 stability limit and get curtailed a lot. But the onus
6 is on the developer to make sure that they're in an area
7 where they can deliver their output to the market. So I
8 guess what I'm saying is you can have the market -- the
9 better way to do it is to let the market decide.

10 COMMISSIONER CLARK: This is actually a
11 really fascinating topic I think. Because it doesn't
12 seem like it should be something that should be
13 impossible to solve. I mean, it's process management,
14 and maybe the box we've been looking at isn't exactly
15 the right box, because we seem to keep having these same
16 issues come up over and over and over again. Maybe
17 there's some other way of looking at it that we can --
18 we have lots of smart economists in the room and folks
19 who might be able to come up with some way to price this
20 particular issue in the sense of scarcity that we see.

21 So anyway thanks to everyone who's been here
22 and look forward to the comments in the record.

23 MR. DOBBINS: All right. We have a question
24 from Commissioner Honorable.

25 COMMISSIONER HONORABLE: Thank you.

1 It's really more of a comment. And I think
2 the gentleman with the last comment really summarized
3 what I wanted to say. We have to find the sweet spot,
4 we don't want -- I have to link to the comment, I think
5 it was, the gentleman from NextEra who said stringent
6 requirements are good, make sure they are serious
7 projects in the queue. But we don't want to make it so
8 difficult that they could be smaller players, but they
9 have viable projects. So I appreciate Commissioner
10 Clark's question, it really gets to the heart of the
11 difficulty in finding the good place, making sure, yes,
12 that there is throughput, that they're getting through
13 the process, but making sure that the projects that are
14 viable are getting through. So thank you.

15 MR. DOBBINS: And before we move on to
16 questions about information, content, and transparency,
17 I had a follow-up question for Mr. Angell. We've heard
18 comments about the restudy process and how that can
19 result in delays in getting information out. Earlier
20 you commented that even when conducting a restudy you'll
21 still complete the study process within the allotted
22 time frames. Would you just maybe give more information
23 on how that is accomplished?

24 MR. ANGELL: Well, and I also mentioned
25 about having augmented staff, the comment about having

1 augmented staff.

2 Well, it's just about juggling resources is,
3 really all it's really about. And if one makes a
4 commitment to study times and sets up their process and
5 resources in order to meet those times -- again, it
6 depends on when their restudy occurs. If the trigger of
7 a higher order queue falling out at the very tail end a
8 week before the study is due, obviously you're not going
9 to make those times. But in general our planners are
10 able to quickly remodel the system and come up with
11 those study parameters. It doesn't generally take -- it
12 doesn't take months to perform these studies.

13 As was mentioned by the gentleman that far
14 end there, the processing power of the tools are very
15 great and do many things. It's a matter of having the
16 resource to be able to analyze it. Because again, at
17 the end of the day there's data and then there's
18 information and then there's taking information and
19 writing a report that provides the customer with what
20 they're looking for. But in general it's about
21 resources and committing those resources.

22 MR. DOBBINS: All right, thank you very
23 much. If there are no other Staff questions -- are
24 there any other Staff questions on this topic?

25 MS. LORD: This question is directed to Mr.

1 Oye. You were talking about the Midwest ISO in the
2 latest round, and you were talking about the off-ramps
3 that were part of that reform proposal. I was wondering
4 if you would talk a little bit about -- where you have
5 seen that work, off-ramp specifically, and maybe what
6 we've learned in various regions? You're part of SPP,
7 part of MISO, you're involved obviously in Colorado.

8 MR. OYE: I think SPP -- MISO doesn't have
9 off-ramps right now built in, they don't. The process
10 that exists today is you can withdraw, but there's not
11 really a point that -- they run a study and you can look
12 at it and go "I want to withdraw and go forward."

13 So that doesn't -- and I think Charles can
14 probably explain this better than me. SPP kind of has
15 that, they got a two-step. It sounds like Cal ISO does,
16 too, I'm not familiar with the Cal ISO. But yeah, MISO,
17 I think this was proposed at a stakeholder -- I'm not
18 sure who came up with it, MISO -- MISO came into the
19 meeting with this idea, "Hey, let's give a restudy
20 automatically for everybody." And then during processes
21 it expanded well, probably need two restudies.

22 MS. LORD: Actually, I was just thinking I
23 probably should have directed my question to Cal ISO.
24 You're the RTO with experience on the scheduled
25 restudies. And I was wondering if you've learned

1 anything from that over time?

2 MR. RUTTY: Well, it seems to be working
3 well at this point. Before we implemented that for a
4 couple years. And the whole integration of the study
5 process, the phase 1, phase 2, the transmission planning
6 and the restudy, all are done, in coordination, so the
7 phases that are developed before those studies, are the
8 same, are in harmony. So as we move forward they all
9 move forward together.

10 As off-ramps, after someone completes phase
11 1 study if they want to withdraw because their costs are
12 too high or it's one of 20 projects that they don't want
13 to move forward with, there are options for them to get
14 part of study process back. If they decide not to,
15 continue -- if they decide to continue on -- then the
16 risk ramps up, they may not get it back. The study
17 deposits aren't really the big one, the big one is after
18 phase 1 they're going to move forward as posting that
19 first financial security which is at risk, that's a
20 major percentage of their upgrades. So -- and then it
21 ramps up again after phase 2; 15 percent after 1 and 30
22 percent after phase 2. So it's ramping up their
23 commitment and our commitment to them as well as we move
24 forward. I'm not sure if I answered your question.

25 MS. LORD: You did, thank you.

1 MR. DOBBINS: If the Commissioners don't
2 have any other questions, we're going to move into
3 questions -- Commissioner Clark?

4 COMMISSIONER CLARK: This isn't a question.
5 But indeed flipping through the filings I noticed Mr.
6 Oye is a graduate of North Dakota State University. And
7 I think deserves to be recognized for that.

8 (Laughter.)

9 MR. DOBBINS: We're now going to move into
10 questions on information and content and information
11 transparency.

12 MS. WOODS: AWEA made an argument that
13 curtailment risk information should be provided on the
14 transmission provider's website under interconnection
15 studies, and we had several transmission providers that
16 argue that this information is already sufficiently
17 transparent. So the question is: What information is
18 currently provided that allows interconnection customers
19 to discuss congestion in order to reach curtailment and
20 what additional congestion and operational data would be
21 helpful?

22 MR. DOBBINS: Sorry, and we'll begin on the
23 left and move down the panel.

24 MR. ANGELL: Yeah, so again in the western
25 system, the posting, again bilateral markets and

1 whatnot, the posting of available transmission capacity,
2 that's on the Website. So if the project knows where
3 they're going to -- a customer is going to know where
4 they would like to site their project relative to
5 transmission plans that are identified in the West
6 consistently, we'd get an indication of where congestion
7 may be based on that information.

8 MS. AYERS-BRASHER: Some of the data is
9 posted, we can find it. But for those that are newer to
10 the queue or not as -- we do a lot of economic studies
11 currently, but not everyone does. And so they need to
12 have that data posted where they can find it, but they
13 shouldn't have to search it out, so it should be very
14 clearly posted or linked on the interconnection site so
15 they are also aware, and right in front of them. In
16 addition having access to the cases earlier and through
17 NDAs and even a small cost, if they can have access to
18 the economic cases, we can either -- if you have a
19 consultant or the internal -- have those products to run
20 those studies, you can do more work. But without the
21 data easily accessible and there, we can't do those
22 things. So some if it's there, but I think it can be
23 improved significantly.

24 MR. BOHACH: Some of the data is out there,
25 for us to do modeling. But the full assumptions that

1 are used to in the ISO modeling helps for us to do those
2 calculations, as well as knowing what conditional study
3 or conditionality you'll have at your GIA or when you're
4 operational. Knowing that early on -- for example,
5 we'll have certain projects, certain transmission
6 projects, that will be conditional on our
7 interconnection, but we won't know the full extent of
8 what that means operationally. What would be the
9 project on until essentially the facilities study when
10 we're going into the GIA. And that can have real impact
11 to the viability of the project based on the finances.
12 I can only inject 75 percent or 50 percent or something.
13 As an IPP, it's that generation that really makes these
14 projects viable and not knowing that until -- I mean,
15 essentially going into it receiving your GIA really
16 hampers being able to make that decision in a timely
17 manner on the viability of your project.

18 MR. EGAN: At PJM, we provide in our
19 studies, we're providing a reliability study, not a
20 market study. But we do provide wind and solar, for
21 example, renewables are getting a capacity so they get
22 38 percent for solar and 13 percent, unless they want to
23 argue more from a technical perspective. So with the
24 upgrades that you're requesting a resource, you would
25 need to build for would be based on the 13 percent

1 portion of your power output. The remaining portion we
2 identify in our studies. These are optional for you to
3 build, you need to come in with a merchant transmission
4 project to upgrade them. The risk would be that you
5 upgrade it and someone else comes along and patches
6 through it and passes the resource and uses up -- so
7 that's the risk for the renewables on the energy
8 portion.

9 The other thing I think is a bit of a
10 chicken and the egg, is that their capability for
11 capacity to prove it once you've interconnected is based
12 on your overall output during the summer period. So if
13 you're curtailed, that would reduce your overall
14 capacity. There are issues on this topic.

15 MR. HENDRIX: SPP, the market monitor would
16 post flowgate data at the most congested areas. As far
17 as the interconnection study process, or a reliability
18 study process, we don't look there at the curtailments
19 on that. We would have customers that have requested
20 NRIS, network resource interconnection service, which
21 would give them a look at constraints that would impact
22 their curtailments. What we've seen, though, is going
23 into facility studies most generators will stick with
24 energy only, knowing -- having that look at what
25 curtailments would do, they chose to go with energy

1 only.

2 MR. OYE: When we -- we buy a lot of
3 projects and we sign PPAs and stuff. When we're
4 evaluating those, we use historical LMPs and information
5 that's already available from MISO, and we feel that's
6 sufficient to do most of our analysis. The other side
7 of this is our company doesn't think transmission
8 providers should be put in a position of projecting
9 future congestion because of variables and uncertainty
10 involved in such assessment. Thank you.

11 MR. RUTTY: I don't believe this has been a
12 big issue with a lot of our interconnection customers, I
13 haven't heard it, that we're not providing enough
14 information. We did post our base cases for all of our
15 studies as soon as they're available, it's only
16 available to market participants who signed
17 nondisclosure agreements with us. That is available
18 right at the beginning. We have an annual process with
19 our transmission owners where we identify pre-unit costs
20 for typical upgrades that are available. So if an
21 interconnection customer wants to do their own study and
22 it identifies different upgrades, they can actually use
23 these costs to kind of estimate what their costs might
24 be compared to what we come up with.

25 Our transmission planning process does

1 forecast congestion for economically-driven transmission
2 analysis through that type of analysis. And I know our
3 markets put out a lot of information that's available
4 online, but again it really hasn't been an issue that
5 I've personally heard, that we're not providing enough
6 information for folks to come into the queue, so --

7 MR. ZADLO: Historical LMPs are insufficient
8 to finance a new power plant. What you have to do in
9 order to finance a new power plant, you have to show to
10 the banks and independent engineer, you have to do two
11 things. You have to do a reliability study, which
12 includes a power flow analysis to prove to them that
13 facility can be interconnected reliably; as well as the
14 other thing you have to do is production modeling case
15 where you're doing an LMP analysis, 8760 in the future,
16 not what happened in the past but in the future.

17 That's the two things we need. We need the
18 power flow study and we need the production modeling
19 study in order to move forward. It's very clear in the
20 LGIP that the transmission owner/RT0 are supposed to
21 provide the power flow cases. I forget what section it
22 is, 4.4 or something like that.

23 Getting those cases is always an issue,
24 always an issue. They say it is CEII, they say it's
25 confidential information, whatnot. We've had to, we

1 actually go as far as call the FERC hotline in order to
2 get the case. So transparency is very lacking there,
3 okay, in the power flow stuff and the production
4 modeling.

5 Production model is a little bit different,
6 we understand, much more sensitive because you would
7 have other generator data and economics in there. But
8 again, certain RTOs are able to mask that information.
9 Again, those are kind of the two sets that are needed
10 for us to project finance the power plants.

11 MR. DOBBINS: Thank you.

12 MR. RICHARDSON: I have a question for the
13 developers in the panel. In your experience in entering
14 the interconnection process, is it your experience that
15 the interconnection procedures and study results
16 sufficiently communicate the assumptions used in the
17 studies? And if not, what changes to the process would
18 you like to see?

19 MR. BOHACH: I would say it really depends
20 on who you're working with, which ISO on that. There
21 are some that, yes, they're sufficient, we know that the
22 tariffs would be able to make those decisions moving
23 along. There are some that we operate in that we're not
24 able to essentially replicate or duplicate the study to
25 be able to forecast and make those business decisions,

1 especially on the timelines that we need. So one thing
2 we would like to see is having the full assumptions and
3 having access to that data to be able to replicate it to
4 mirror/validate what we're seeing and what we're getting
5 back.

6 MS. AYERS-BRASHER: And I'd agree with that.
7 When we work with a consultant to get an upgrade done,
8 we know what all the assumptions are. We're paying for
9 these studies just like we're doing that for the
10 consultant, so we really should know all of the
11 assumptions that are going into our study and we should
12 be able to replicate those studies. And we also cannot
13 always replicate those studies to ensure that there
14 aren't errors in the cases, because we've had
15 experiences where we've had to deal with that. So if
16 we're also -- and it allows us to have that
17 communication back and forth, if there is a question --
18 because nothing is necessarily perfect -- but we need to
19 be able to ask those questions. And without those
20 assumptions, we're not able to always do that as well.

21 MR. ZADLO: I'll say this as a former
22 transmission planner. Assumptions will dictate what
23 your study is going to uncover. You can make any
24 overload appear or disappear based on your generation
25 dispatch and your load assumption. And transparency on

1 how these cases are developed upfront before the
2 analysis happens is paramount.

3 MR. DOBBINS: Would anyone else like to
4 comment on this topic? Sorry. Would anyone else like
5 to make a comment on this topic?

6 MR. RICHARDSON: And in an AWEA petition
7 there was some comment in regards to capacity factors
8 used to model generation. So the question for everyone
9 would be how were those capacity factors determined?
10 And for the transmission providers on the panel, where
11 are those capacity factors located? Are they in the
12 tariff or are they in a business practice manual or are
13 they available to developers?

14 MR. ANGELL: So for Idaho Power, capacity
15 factors are not in the tariff and not in a business
16 practice. However, the capacity factors being used are
17 discussed during the scoping meeting at the very
18 beginning. As far as the reliability studies, this was
19 mentioned earlier, power flow, within the localized area
20 we use a hundred percent capacity factor such as we know
21 when the wind project or solar project is producing
22 their sufficient capacity in the area to transmit.
23 However, once you move away and get into again talking
24 about the western system paths that are defined, we look
25 there and we look at historical capacity factors of the

1 other units in the system and we apply those capacity
2 factors along with this project as it's coming through.
3 And, again, when we do those studies, one of the things
4 we do look at on those particular paths, we ensure that
5 this project does not limit the path capability that
6 previously existed, so we won't let the project
7 adversely impact those paths.

8 MS. AYERS-BRASHER: So we're able to find
9 them in a general comment that's posted. And that's
10 fine, as we know what they are. However, there are
11 certain allowances that we can elect for a higher level.
12 And in that case, I guess the only thing there would be
13 is if we elected a higher level and we moved forward at
14 that level, then that needs to be held for future
15 studies and future generators and then not put -- in
16 some cases we are then dispatched in the wind projects
17 for instance, and if we had elected it at a higher level
18 that should be held, we shouldn't just be dispatched for
19 everyone else's.

20 MR. BOHACH: Regarding specific NCF moving
21 forward, we would probably put that in our
22 post-conference comments.

23 MR. EGAN: I believe I mentioned before 13
24 and 38, wind and solar, that is in our manual the
25 customers can request higher, so if you had, for

1 example, solar with tracking, we see as high as 67
2 percent capacity factors on solar. And if we study them
3 as capacity, they're entitled to that as a capacity
4 output. So the issue gets into, and that's the energy
5 portion, in the coupling of that to maintain the
6 capacity, that does become a difficulty for the
7 developer, but that's not an easy solution.

8 MR. HENDRIX: In SPP, we felt this was a
9 reliability study. We will have all the generation in
10 the local area as full nameplate, and then for variable
11 resources beyond the outer areas we'll have little over
12 20 percent. And the week after that, the studies, I
13 believe we have it posted on our website.

14 MR. OYE: I really don't want to comment on
15 this one for MISO because I don't remember exactly what
16 they are. But my memory is that I think they used
17 historical values to come up with stuff, and they have
18 run studies to kind of see what real-time operations
19 that they looked at to kind of set it, so --

20 MR. RUTTY: Very similar to the other
21 panelists, the ISO, we don't post it -- I mean, we don't
22 have in our tariff, we don't have it in the BPM because
23 they do change. The technology is getting better, solar
24 output is getting better, weather patterns have changed.
25 We've noticed changes in the different regions. So we

1 do discuss it with interconnection customers at the
2 scoping meeting, what we're setting their unit at. And
3 it varies by region, Northern California versus Southern
4 California versus the desert areas. But we do utilize
5 capacity factors so we don't overbuild the system. And
6 I guess that's about all I have to say on that one.

7 MR. ZADLO: I think it's a little less
8 important exactly what number those capacity factors
9 should be, we can debate that. I think it's more
10 important that those study assumptions be established
11 before the study takes off.

12 MR. DOBBINS: And with that, we plan to
13 break for lunch, unless there's any questions or
14 comments from our Commissioners.

15 So we will restart questions -- panel 3 at
16 1:00 p.m. There are a lot of great options around here
17 for food. We have a great cafeteria in the building as
18 well. I've just been told it was closed, so there are a
19 lot of trucks outside, food trucks nearby.

20 (Whereupon a lunch recess is taken.)

21 MR. DOBBINS: Okay, we're now ready to start
22 panel 3 of today's conference. This panel is on
23 certainty and cost estimates and construction time.
24 We're going to ask the panelists to introduce themselves
25 and make their prepared remarks, which were submitted

1 into the docket, or just to tell us one or two points
2 they would like to make today. Panelists, we ask that
3 you please keep your remarks under two minutes. We have
4 a timer at the front to let panelists to know how much
5 time they have left. We'll start on the left and move
6 down the line.

7 I'm sorry, real quick before we start, I
8 just wanted to acknowledge Chairman Bay who just joined
9 us in the room and ask if he wanted to make any comments
10 or any questions.

11 Okay, and with that, we'll start.

12 MR. ALIFF: Thank you again. As I said
13 before, my final is Tim Aliff, director of reliability
14 planning at MISO and my purview does include generation
15 interconnection process for MISO. As far as my opening
16 remarks here, MISO's looking at the technical conference
17 as a way of gathering best practices. And we've heard a
18 lot of practices that we have brought with our
19 stakeholders already and we look forward to continuing
20 that discussion with our stakeholders as well as the
21 guidance that the Commission has provided us.

22 There was some questions earlier about
23 regional differences, I just wanted to comment on that a
24 little bit. Regional differences should be allowed, but
25 where there are conflicts in those differences, that's

1 really where the focus needs to be addressed and that's
2 where the effort and time needs to be put in, not just
3 making everybody have a uniform process.

4 As far as that cost estimates and the
5 construction time, there can be tradeoffs with providing
6 more accurate results quicker. Right? It takes longer
7 time to produce those more accurate results, which then
8 also leads to longer time in the queue. You can provide
9 cost estimates quicker, but then it's not necessarily
10 the most accurate.

11 And finally from MISO's perspective, and
12 specifically, MISO has a provision in our tariff that
13 allows for a customer to withdraw if those costs exceed
14 25 percent between the system impact study and the
15 facility study phase. And we have had very rare cases
16 where that cost has exceeded the 25 percent. We've seen
17 costs go down, but in a few instances we've seen that
18 occur greater than 25 percent. Thank you.

19 MR. GOSSELIN: Dean Gosselin with NextEra
20 Energy Resources.

21 This morning we had comments around the
22 interconnection study process and the certainty and
23 timing of those outputs from that process. For this
24 panel my comments go generally to what happens after the
25 study process. So we saw network upgrades and those

1 network upgrades have a proposed cost and an estimated
2 cost and a proposed schedule. The way that the
3 construct works today is the transmission owner that
4 we're interconnecting into cannot meet our schedule, we
5 can challenge that and schedule and ask that under the
6 option build them ourselves. We're really talking about
7 generally about direct assignabilities, and those that
8 have cost responsibility 100 percent of and they're
9 typically the switchyard or the point of interconnection
10 on the system where we're cutting into the system to put
11 a generating plant on line.

12 And where -- we've had several instances
13 where the transmission owner has tendered us that option
14 to build it ourselves, and when we're taken it what
15 we've found is our costs are well below their estimates,
16 even with our contingencies in it, and our schedule is
17 much as half of what their schedule is. So what we're
18 asking for here today is the idea that we're able to
19 self-construct, that we're given the absolute right to
20 self-construct those facilities where the direct
21 assigned, and a hundred percent our cost responsibility.
22 Thank you.

23 MR. KELLY: Good afternoon. My name is Paul
24 Kelly. I work for NISCOT out of Northern Indiana. And
25 today I'm here on behalf of the MISO transmission owners

1 as vice chairman. I'd like to thank FERC for taking the
2 opportunity today to pick up a very important topic.
3 We'd like to make three points today across the two
4 panels I'll be speaking on, and I wanted to refine the
5 concept around respecting regional differences. We've
6 heard a lot from the panel on that today. And the one
7 statement that we make is that, particularly from MISO I
8 think a lot of the best practices in the opportunities
9 to optimize and draw some efficiency in the GIP, has
10 been presented today and also was reflected in a lot of
11 the reforms that were proposed at the end of 2015.

12 We thank FERC for the opportunity to circle
13 back to those because it was dismissed without
14 prejudice. So with the opportunity for regional
15 differences to take the direction from FERC that we take
16 from this technical conference and then be able to take
17 that through our stakeholder process and having enough
18 time to implement that as would be able to fit the
19 market there for MISO.

20 The second statement would be that I know
21 one of the driving features for part of this technical
22 conference were some proposals. And from the owners, we
23 just wanted to ask that FERC respect the reality that
24 there's a difference between approving a process and
25 driving efficiencies, versus shifting risk onto

1 different parties. And as FERC recognizes the issues, I
2 think, that have been considered in the past, there are
3 inherent risks for certain business activities and there
4 can't be a guaranteed insurance policy. So to the
5 extent that today is about finding those efficiencies
6 and best practices, the owners are very supportive, but
7 also recognizing that a balance has to be struck and
8 that certain risks can't be mitigated entirely.

9 And then finally just to recognize, and I
10 think it's already been mentioned here today, that there
11 are tradeoffs and there are tensions, and that we want
12 information to be timely and accurate and
13 cost-effective, but often to influence ones will show
14 there's other variables in it as well. And so the
15 owners would recognize again there a balance has to be
16 struck and that part of the procedures that we have in
17 front of MISO recognize at a different phase as we have
18 different escalating levels of commitment. We thank you
19 for the time and look forward to the discussion today.

20 MR. MARTINO: Good afternoon. My name is
21 Omar Martino, I am the director of transmission
22 strategies with EDF Renewable Energy. EDF Renewable
23 Energy is a subsidiary of Electricite de France, a
24 French utility electric company. In North America, EDF
25 Renewable Energy has developed over six gigawatts of

1 generation since 2012. EDF Renewable Energy currently
2 owns 3.1 gigawatts of generation and we have
3 approximately 1.1 gigawatts under construction and 10.5
4 gigawatts under operation of internal services
5 agreements. I want to thank the Commission and also
6 Staff for inviting me to speak here today.

7 One topic of concern is the ability to get
8 accurate RTO cost estimates earlier in the process. The
9 RTOs usually provide cost estimates of a study stage
10 that is based on per-unit cost without full knowledge of
11 what the transmission owner will actually require. When
12 the transmission owner pays close attention at the
13 facility studies stage, new costs may arise that were
14 not communicated earlier, and some of these differences
15 can be quite large and dramatic.

16 The generation developers must also have the
17 ability to assess congestion risk. Interconnection
18 studies are not being provided this information; we have
19 seen on several occasions where generation projects
20 interconnected the grid, they followed the GIP rules,
21 and then they severely faced congestion, and the only
22 option for those projects at that time is to fund
23 upgrades outside of the interconnection process. And
24 some of these issues are discussed in earlier dockets
25 that were filed at FERC.

1 One of the means that we think that we can
2 propose to address congestion and curtailment at the RTO
3 is the fund load is reasonable factors on a standardized
4 concept such as, for example, below five percent. We
5 believe that if these studies, these standards are
6 applied consistently and continuously, the grid will not
7 be underbilled and it will be able to accommodate new
8 projects while protecting some of the existing assets.

9 To conclude, we think there are several
10 ideas we can utilize to enhance the process and improve
11 the process. I believe that reducing the
12 interconnection time frame to 12 months can reduce the
13 risk of construction delays and cost estimates. We
14 believe that having a three-process milestone can also
15 reduce the risk of withdrawals, one milestone for entry,
16 one milestone for exit, and one milestone in between in
17 the process to make a decision. We also believe that,
18 giving the interconnection customers the ability to
19 self-fund interconnection, facilities and specifically
20 transmission facilities can reduce the uncertainty and
21 the withdrawals that the customer is faced by having
22 longer schedules. And at last we believe that
23 congestion is a significant issue of the grid level and
24 we have to have a process where it takes a look at
25 congestion and resolve the issues for both existent and

1 new asset integrating into the grid. Thank you.

2 MR. McBRIDE: Good afternoon. My name is
3 Alan McBride. I'm the director of transmission
4 strategies and services at ISO New England. My
5 responsibilities include interconnection queue. I want
6 to thank the Commission for the opportunity to speak
7 today at today's technical conference.

8 The edification of cost schedule estimates
9 for interconnection upgrades is an important part of the
10 overall interconnection process. The ISO, however,
11 depends on who see estimates, however, does not produce
12 these estimates. This work is performed by the New
13 England transmission owners. Once an upgrade has been
14 identified, the ISO knows that there is a clear tradeoff
15 between the desire for cost and schedule adversity and
16 the time cost taken to prepare the estimate. It would
17 seem appropriate that, in order to keep the study
18 process moving, estimates should not be meant to be
19 highly accurate during the study phase. It may be worth
20 considering whether different study management designs
21 contribute to cost and schedule uncertainty.

22 As noted in the AWEA petition, some
23 redesign can result in significant re-estimation of
24 costs, especially when earlier queue projects withdraw.
25 In New England interconnections are energy studied

1 serially. In addition, generators do not receive
2 capacity interconnection service until they have
3 achieved commitment in the -- forward capacity market.
4 As a result of these features, it may be the case that
5 New England appears to incur less uncertainty from an
6 upgrade cost perspective. Thank you.

7 MR. RUTTY: Good afternoon again. Steve
8 Rutty from California ISO, director of grid assets. We
9 went through that in the earlier sessions, so I won't
10 bore you with all that again.

11 For this session just a couple of points.
12 The interconnection process we developed at the ISO was
13 an evolving process, it took many years. There was a
14 lot of give-and-take by the stakeholders to make it
15 work. For instance, the interconnection customers have
16 agreed to post-financial security, serious amounts of
17 money to move forward. At the same time, our
18 transmission owners have stepped up to provide cost caps
19 early in the process that allows the interconnection
20 customers certainty to move forward. If the actual cost
21 of these upgrades go above that cost cap, the
22 transmission owners are then required to fund it. So
23 getting all the parties to give and take through the
24 process was very important and makes our process work.

25 The only other thing I wanted to say was,

1 based on how accurate the studies are early is a direct
2 relation to the amount of time that we allow for the
3 studies and to put out accurate estimates. So that was
4 another give-and-take. There was a need for the
5 interconnection customer to have their studies early and
6 quick in the process done, and then there's also, "Hey,
7 I want it to be accurate." So coming up with a good
8 balance was very important there as well, so --

9 MR. VAIL: Rick Vail, vice president of
10 transmission with PacifiCorp. Just a couple of points
11 when it comes to cost estimates and the certainty around
12 that. PacifiCorp has about 16,000 miles of transmission
13 line, so building projects and interconnecting things to
14 the transmission system really is something we do every
15 day. So when you start looking at the queue process, we
16 have a lot of experience on what the costs should be,
17 even if it's at a per-unit or a lock level. Quite a bit
18 of certainty on the timing, at least from the PacifiCorp
19 experience, how long it takes to construct some of these
20 facilities. We certainly have developers on a quicker
21 timeline, not only on whether it's going through the
22 queue process but also the construction process as well.
23 And we do work with them as long as they're following
24 our standards, and they can do some of their own
25 construction work.

1 But just like anything, the more detail you
2 want, the more certainty you want or around those
3 estimates, the more time you have to spend around it
4 upfront. That's the kind of same thing with the
5 construction. And again, it does depend on where it's
6 at, what are the purviewing activities that are required
7 to get something built.

8 So there's some variables there, but I
9 think as long as you're communicating all this upfront,
10 at the very beginning of a project, that first project
11 scoping meeting having those conversations and making
12 sure you're detailing out that these expectations are
13 with each other, to me it does seem very critical when
14 you get down the road. If you are not communicating
15 that this is a plus-or-minus-30-percent estimate to a
16 customer and then you provide it and then they come back
17 and now you're saying it's going to be 30 percent more,
18 that is probably about the worse thing you can possibly
19 do. So I think having that communication and being very
20 explicit of, "Here's where we think we have our
21 expertise here, what are assumptions are," what we base
22 it on, and do that upfront, goes a long way to working
23 through issues on the back end.

24 MR. DOBBINS: Once again, we'd like to say
25 we thank all the panelists for coming and participating

1 and providing their opening remarks. At this point
2 Staff will now move into asking questions. We ask that
3 you please limit your responses to a minute so that
4 other panelists have time to speak, and apologies once
5 again in advance if we're unable to hear from everyone
6 on every topic.

7 What is the frequency of disputes regarding
8 interconnection configurations for direct assignment and
9 network upgrade calls? How are such disputes typically
10 resolved? And do you have any suggestion for how they
11 can be avoided?

12 So we'll start on the left.

13 MR. ALIFF: So for MISO, we typically don't
14 encounter disputes related to interconnection
15 configurations or network upgrade costs. But when they
16 do arise, we try to resolve those on a more informal
17 basis, working with interconnection customers and the
18 transmission owner to work through those areas of
19 concern. And if that process doesn't work, then we do
20 have other opportunities to escalate that and to provide
21 more formal matter to work through the dispute
22 resolution processes. But for the most part we handle
23 that through the informal discussions. How can you
24 resolve some of that? You're providing information,
25 like has been discussed earlier, additional model review

1 and further discussion through that time frame, maybe
2 upfront, maybe during the process depending on where the
3 concern or issue is coming from.

4 MR. GOSSELIN: Dean Gosselin with NextEra.
5 So we do have disputes. We have disputes over what is
6 the configuration of which yard we will build and
7 interconnect into. And what we find is different
8 standards amongst different transmission owners, and
9 they want us to build to effectively up their standard.
10 There's very little latitude or any leniency in terms of
11 what is that standard? Even though we may be able to
12 show them that within the same RTO footprint amongst
13 another transmission owner, we're able to build a
14 cheaper facility. And I talk about things like ring bus
15 versus a breaker-and-a-half scheme, and it's just the
16 amount of equipment and the amount of cost that goes
17 into each of those.

18 And most of it is about providing future
19 flexibility. Well, in our case, we clearly don't care
20 about future flexibility, we care about interconnecting
21 our facilities into the grid at that moment and
22 providing the necessary reliable operation of it.

23 So the dispute resolution is a discussion
24 with the engineering groups of the relevant transmission
25 owners. And ultimately we lose, because if you hold out

1 nothing's going to change. No standards change. And
2 therefore you don't get your project done, so you have
3 to perpetuate. I don't think there's a real sense of
4 building prudent practice, as opposed to this is our
5 standard, we're doing it this way, there's no latitude.
6 Thank you.

7 MR. KELLY: Paul Kelly for the MISO
8 transmission owners. I was listening to Dean's
9 statements and it was occurring to me that, because of
10 the companies that are collectively represented in the
11 transmission owners, we're sympathetic in a lot of areas
12 because many of us own generation, been through the
13 queue on that side, versus those of us that own
14 transmission as well. So we've seen both sides of it.

15 I would say where we come down on it is
16 that when you're going through the GIP it's a
17 reliability analysis and you're trying to make sure that
18 the grid can provide the level of transmission service
19 necessary for the level of the interconnection that's
20 being requested. So that's always for us has continued
21 to win the day. And as far as the number of disputes I
22 would say experienced at the collective level, it's a
23 mixed bag. But I was even, in reviewing Order 2003,
24 just reminded that I don't think that some of these
25 issues have gone away, really it just comes to the scope

1 the work that's necessary to provide a reliable service,
2 the cost related to that to that.

3 So for the owners, I think we would say we
4 understand, on the interconnection side wanting to have
5 a cost-effective solution, because you are entering a
6 competitive market in these opportunities and you want
7 to be able to be competitive, so lowering your cost of
8 entry is always important. As somebody that wears the
9 TOP hat at on the other side of it, we'd say that it's
10 very important that we maintain reliability. And I
11 understand the words like about the "overbuilt" come
12 into it, but at of the end of the day we're trying to
13 make a decision of what do we need to do to the system
14 now so the asset which is going to live for decades can
15 reliably serve. And when you have to try to make that
16 decision at a point in time, I think reliability needs
17 to continue to remain the same decisions. Thank you.

18 MR. MARTINO: This is Omar with EDF. We do
19 see disputes. Both of the disputes are both on costs
20 and schedules on the interconnection facilities. Now
21 we're experiencing, our review, some of the RTOs are not
22 very flexible in meeting the requests of the
23 interconnection customer. They don't provide the
24 flexibility to achieve a certain date or to have more
25 discovery on the fundamental reason of the changes of

1 the costs. For example, what we have experiences that
2 -- in MISO, for example some of the TOS will not get
3 involved at the system impact study stage, at the level
4 of detail and the level of expertise and we see it more
5 at the facility study stage. So some of those costs can
6 change dramatically between system impact and facility
7 study.

8 And also the utilization of per-unit costs
9 rather than an actual construction, actual material
10 figures, earlier in the process. We also see that the
11 disputes often on schedules are due to having a lack of
12 participation of effective systems.

13 In fact, again, from our experience we have
14 a number of LGIAs that are closed, they're executed, and
15 there's no or little information about effective
16 systems. And the risk or exposure that some of them are
17 experiencing are either not identified or they're
18 identified but they're essentially not costed, because
19 the affected system simply does not provide that
20 information. So providing that information earlier in
21 the process would be key to relieving some of these cost
22 disputes and construction schedules.

23 And one last comment to end, we really think
24 that having the flexibility to build interconnection
25 facilities and to build transmission can reduce some of

1 these disputes, both from the interconnection side and
2 on the transmission side, and also will provide
3 interconnection customers with the flexibility needed to
4 achieve a particular COD.

5 MR. McBRIDE: Thank you. In New England, to
6 deal with the interconnection configuration discussion,
7 we have some planning procedure guidance on standard
8 substation design and standard substation requirements
9 for new generation interconnections. So those are known
10 to everybody as they come to the table so people know
11 going into the process what their direct interconnection
12 is likely going to look like. I think that helps
13 people's understanding of what they're heading into. I
14 think overall in New England disputes have been rare,
15 there are probably a number of reasons for that. We
16 have built an amount of transmission in the region over
17 the past recent years, so I think that's given
18 transmission owners a lot of experience in preparing
19 estimates and in preparing schedules.

20 So for the most part things work out. In
21 the case where there is a dispute that we would seek to
22 help communications between the interconnection customer
23 and the interconnection transmission owner and work
24 through the various mechanisms that are provide in the
25 tariff. There are cases, and I think there was a recent

1 case where the issue may come down here in the form of
2 an unexecuted interconnection agreement and then
3 resolved through that process. So that is something
4 that has happened. But that's just one recent example I
5 can think of for that process.

6 Finally, I think I'd agree that
7 communication is important and does help. If in
8 presenting an estimate and a schedule, if it's
9 explained, the level of accuracy that was involved in
10 the schedule, what would happen next as the project
11 moves forward to more certainty and more completion in
12 terms of estimate updates, all of those I think can help
13 give customers the understanding of how the process is
14 going to evolve.

15 MR. RUTTY: Very similar to some of the
16 other panelists. The ISO holds results meetings with
17 all of our interconnection customers to discuss study
18 results. We bring into those meetings the engineers
19 that did the studies for both the transmission owners
20 and the ISO. We have our interconnection specialists
21 there to be able to log and note any discrepancies,
22 anything that needs to be resolved.

23 And pretty much it's a very open,
24 interactive process and concerns are resolved fairly
25 quickly. I would say that we really do not have too

1 many problems, and a lot of that is because it's a
2 transparent process upfront where we post the base
3 cases, where we post our per-unit cost guides, we
4 discuss what the scoping meeting might be, how they're
5 going to be studied and to what factors and so forth.
6 And if there are any disputes -- so we do have our
7 dispute resolution process that runs through our
8 executive team. But again, I think it's been years
9 since we've had to use that:

10 One point on effective systems, one thing we
11 did hear loud and clear from our interconnection
12 customers was that very issue about bringing effective
13 systems into the process early. And we advised them at
14 the very first scoping meeting, we post on our website
15 what the effective systems on the various areas are that
16 you might be trying to interconnect to and who you would
17 be likely dealing with. The ISO is not in a position to
18 steady effective systems, but we do bring them, very
19 quickly identify them, and allow them to identify
20 themselves in study process if they are truly affected
21 and to work with our interconnection customers to
22 resolve those issues. Thank you.

23 MR. VAIL: This is Rick Vail. I don't have
24 a lot to add to that, again I would just say, trying to
25 get to those expectations upfront, I think one of the

1 most important things is it's truly a reliability
2 assessment upfront. And so from a Pacificorp standpoint
3 we don't find ourselves in a dispute situation very
4 often. Certainly, if there are any issues that come up,
5 and again address that head-on with the customer right
6 away and make sure you're communicating.

7 But having that reliability assessment and
8 ensuring the reliability of the system I think is very
9 important. And one of the difficult things is trying to
10 communicate to developers sometimes the requirements
11 that we are under, whether it happens to be a NERC
12 reliability standard and along with that standard comes
13 a methodology, and that methodology you've been through
14 audits with your regional entity with -- so changing a
15 standard, on the face of it I don't think any standard
16 should be overbuilt or you should have way too much of a
17 safety factor built in. But it is not simple or easy
18 for a utility to just change their standard if there is
19 a whole line or sequence of other processes or
20 requirements that go along with that. So that was my
21 speech on that one.

22 MR. DOBBINS: I had a followup question for
23 Mr. Gosselin. You indicated that there is at times a
24 push for you to change or do your configurations based
25 upon future flexibility. Just to clarify, are you

1 saying future flexibility in case of your actual
2 operations are different than what you have modeled, or
3 is this in anticipation of other projects being on line
4 and needing to use those facilities?

5 MR. GOSSELIN: Just a couple of examples.
6 We've had one recently where the transmission owner has
7 tendered us the opportunity to self build. And it looks
8 like our costs from their estimates, original facility
9 study estimates, are going to be two-thirds of what
10 their cost was. However, in their standard they had an
11 additional 10 acres of land, including prepping that
12 land. And that's expensive, so you have to buy the
13 land, you have to prep it, so new service. And
14 presumably ground grid and other things that also add
15 expense and fence it.

16 When we're building it we're building it for
17 us and only us and our future. Their idea was they
18 would expand it in the future and potentially tie
19 someone else in there. So there's a gap in expectations
20 right there. Ultimately we resolve that piece of it
21 fairly simply by saying we will option the rights for
22 the land for them if they want to expand in the future,
23 and it's their cost, not ours. So we're restricting
24 when I say we want facilities that serve our needs of
25 our facilities that we're asking to interconnect now

1 until the end of that project. There's other instances
2 where I talked about a ring bus configures versus a
3 breaker-and-a-half scheme. So in this case three
4 breakers versus five breakers. And about two more
5 breakers is more than a million dollars to install, plus
6 -- plus work and other things associated with those.

7 And ultimately we lost on that, and that was
8 really because they said, "That's our standard, we're
9 not going to let you build a ring bus on here," even
10 though we built a very similar interconnection the prior
11 year within the same RTO's footprint for a different
12 transmission user that allowed us to do a ring bus. So
13 in some cases we're able to work through, in other those
14 cases, they insisted for their own standard.

15 Certainly, breaker-and-a-half schemes are
16 more easily expandable in the future than a
17 configuration associated with a ring bus, but they
18 clearly weren't thinking from the perspective of what is
19 adequate to meet reliable electric service on the grid?
20 Thank you.

21 MR. QUINN: I guess I have a question about
22 the degree to which you'd have these discussions between
23 interconnection customer, how much the ISO can play a
24 role to mediate those disputes? And if there's not much
25 of a role, the independent entity variation that we use

1 to justify deviations from the pro forma for the RTOs is
2 premised on this idea that there's independence and that
3 the independent system operator has no incentive to do
4 anything for the disadvantaged customer if the RTO can
5 play a role to help mediate inner disputes. Are there
6 parts of the LGIA where we should grant the independent
7 entity variation because it really is the transmission
8 owner that has most of the control over the process and
9 so the underlying premise of independence, the variation
10 doesn't really kind of stand up?

11 MR. GOSSELIN: Dean Gosselin again.
12 Specifically with regard to the two situations I just
13 laid out for you, which truly happen: The RTO basically
14 had no dog in that fight, they said, "We're not going to
15 be a party to dispute resolution, deal with it directly
16 with the transmission owner." And so for us, you can
17 think of it like the shop clock's running, we buy
18 equipment, we're spending hundreds of millions of
19 dollars in these particular cases in terms of advancing
20 our project and our project development. We don't have
21 time to take it to arbitration, take it to you, take it
22 to someone else, right; we lose, we have to capitulate
23 and move on, we have no choice. So as far as the
24 independent variation goes, there are different
25 standards out there, we recognize that. However, do

1 those standards truly meet pre-utility practice tests
2 that we all have to apply as well?

3 MR. MARTINO: This is Omar with EDF
4 Renewable Energy. I believe the RTO does have leverage
5 to resolve the disputes. However, they don't use their
6 leverage or they don't usually get very involved in the
7 matters. What I mean by having leverage, the RTO does
8 require the T0 to become more involved earlier in the
9 process. There is no justification, if you will, to
10 have a T0 in an affected system not participate in the
11 study plan or not participate in the interconnection
12 process, and as a consequence of that, have executed
13 LGIAs and risks given to the interconnection process.
14 Because the RTO, in that case indicates that we're not
15 going to deal with the affected systems, this is going
16 to be the building of the interconnection customers, and
17 if the affected system is not willing to be dealt with
18 then it's unresolved. But I believe there are ways to
19 do that, and also there are ways to do that as well with
20 no jurisdictional entities.

21 The point here is that the RTO plays a very
22 neutral role, but I believe they do have the leverage to
23 mandate participation and to mandate closure on some of
24 these disputes so we can de-risk some of the issues that
25 the interconnection customers are facing. Similarly on

1 the standards issue, the RTO will play no role whether a
2 breaker and a half or a ring bus is the right solution,
3 because that's the standard of the TO. I can personally
4 respect that.

5 But on the RTO level, the RTO should have a
6 say and should have a clear indication and criteria to
7 be able to say that ring bus or breaker and a half is
8 actually justifiable for that part in particular as a
9 reliability entity. So the point there is whether or
10 not there are standards by the TOs, by the utilities,
11 the RTO as a reliability entity should be able to say
12 whether that standard in that particular case makes
13 sense, and therefore take up decision on the issue.

14 MR. DOBBINS: Mr. Kelly.

15 MR. KELLY: Paul Kelly with the MISO
16 transmission owners. I just wanted to say from past
17 experience, the owners have worked with the RTO in
18 resolving matters like this. I think the other piece is
19 to recognize there are dispute resolution procedures
20 that are part of the GIP's generally. It's not that
21 these are wholly absent, and I'm just recognizing that
22 certain parties have said, "We had a dispute, we didn't
23 like the outcome, we chose not to avail ourselves of
24 that particular procedure and we weren't happy with the
25 outcome." And I understand that, because, again as a

1 transmission owner, I think with different business
2 models here, we've seen both sides of that equation.
3 But I just wanted to highlight the fact that there are
4 different dispute resolution procedures available.
5 Thank you.

6 MR. DOBBINS: Mr. Aliff?

7 MR. ALIFF: Tim Aliff with MISO.

8 So I do think the RTO does play an important
9 role. And the fact that we don't have a dog in the
10 fight I think is a valid reason why we should play a
11 role. Because we're making sure the reliability of the
12 system is maintained. And also there is the equity
13 issues too. If we start allowing individual
14 interconnection customers to mediate from planning
15 standards, then you end up with a previous customer
16 built to a level that a later customer did not build to
17 that same level, which could have a reliability impact
18 down the road. And also from an efficiency standpoint,
19 building substations that have future ability to expand
20 on may be a cheaper alternative down the road for all
21 other customers, and MISO does have a provision that
22 allows for in those type of scenarios, shared network
23 upgrade costs to be -- those upgrade costs shared
24 amongst others that come in behind the initial
25 interconnection customer.

1 MR. DOBBINS: Are there any other comments
2 on this topic?

3 MR. McBRIDE: I think there may be a
4 specific difference here in New England on
5 interconnection configurations, and I think it's an
6 example of the RTO or ISO can play. Even though we have
7 several transmission owners in our footprint, we do have
8 a common substation design and interconnection
9 configuration standard that would apply across our
10 system. As I said, that's in our planning procedures
11 and that's known to customers when they come into the
12 process. And I think beyond that -- and I think I'd
13 agree with the way Tim put it -- the ISO is a party to
14 the interconnection agreement and obviously oversees the
15 overall interconnection process.

16 So we can convene with the interconnection
17 customer, the interconnection transmission owner, and we
18 do that. And we'll ask questions of why something might
19 seem different in one part of the system versus in
20 another part of the system, and it could be there's good
21 reason for that. But that's the kind of question we can
22 ask with the visibility that we have throughout the
23 region.

24 MR. DOBBINS: All right. If there aren't
25 any other comments, we have a question for the two -- on

1 the panel. Are there any elements that you commonly
2 received inaccurate estimates? And how do final
3 estimates compare to the estimates throughout the
4 process?

5 MR. GOSSELIN: Dean Gosselin with NextEra
6 Energy. So the vast majority of our interconnections,
7 it's well over 100, have come in under the estimate. So
8 the estimate's -- inflated, but contingency is in there
9 more than sufficient to cover them. However, we have
10 had several what I will call "epic fails" where the
11 actual cost came in in multiples of what the estimate
12 was without really any -- well, in one of the cases no
13 heads' up until after the money is spent, which may have
14 changed a decision. In the other cases I would say as
15 soon as they knew.

16 However, by that time it's too late because
17 we've spent this huge bulk of money trying to build a
18 generation project to tie into the system. So we're
19 swept in the current, if you will, and have to accept
20 it. So it's gone in both directions on us.

21 Now, ultimately what we want is accuracy.
22 Right? Because if you think about the process we're
23 going through and the thought process of a new project,
24 we're trying to price in every component accurately, and
25 then we're pricing it to a customer, and if we get that

1 wrong, high or low, we may not have one competitive
2 solicitation or we may have built something that we
3 shouldn't have built. Right? So it really cuts both
4 ways, we want accuracy, accuracy is important.

5 I think the second thing we're not really
6 talking about is schedulewise. We find in the majority
7 of our cases that schedule and schedule completion is
8 challenged against what the estimate was. And there's
9 no consideration for that from the transmission owner,
10 it's clearly they're mandated to build it, they don't
11 have any liability for missing it.

12 But we need them to be accurate, right, we
13 need them to be accurate. It's part of why I asked --
14 to the extent that it's just our interconnection
15 facility that is affecting our cost, let us go build it
16 because we can manage those; cost and schedule, they
17 both matter. We don't want to be sitting there with
18 several-hundred-million-dollar renewable facility that
19 can't generate because the interconnection's not
20 complete. And we find ourselves more in that situation
21 than in the cost-overrun situation. Thank you.

22 MR. MARTINO: Omar Martino with EDF
23 Renewable Energy. I agree with the previous statements.
24 We see common issues both from the interconnection and
25 on the transmission side, and we see them both on

1 schedule and costs. Just to cite a very few examples on
2 the interconnection side, I have to say that they're
3 rare, but they do happen on cost deviations. But on one
4 particular deviation we saw cost deviations on almost a
5 hundred percent, and that was well after the LGIA was
6 executed with respect to the start project. So that can
7 happen and that can take significant financial impact to
8 the project.

9 On the transmission side, we also see those
10 very large deviations. Those deviations can be as high
11 as 70 percent. And to that point, on the transmission
12 side a company like EDF Renewable Energy needs those
13 upgrades, needs those improvements to integrate. And
14 there's no other option, there's no just simply fund
15 those large deviations.

16 The schedule is a significant, issue and
17 it's a significant but it's also a very constant issue.
18 I can hardly say on a number of very, very few times
19 when the actual schedule by the interconnecting
20 transmission owner was actually met. So schedule issues
21 are seen all of the time.

22 One point I do you want to say here, and
23 see if I can try to differentiate, is that on the cost
24 estimates I want to make a very slight distinction, but
25 I think it's also an important distinction. On the cost

1 estimates they essentially go into two buckets. One are
2 the physical upgrades whether they're on the
3 interconnection side or the transmission side, those
4 physical upgrades they're going to have; and then on the
5 other side, the second bucket, that I don't think we
6 have discussed here today, is those contingent upgrades
7 which are part of the schedule and they're part of the
8 cost responsibility of interconnection the study
9 process. They can be very large deviations on those
10 contingent upgrades, whether they are required because
11 of real studies or modifications of the queue or
12 whatever the reason might be.

13 But the fact of our experience is that we
14 see a great deal of variations just in the study
15 process; this is not at the termination of the LGIA, or
16 I should say the completion of the LGIA and the
17 construction of facilities. I'm talking about through
18 the study process we see very large variations of costs
19 on a schedule, and I think that is an issue that is very
20 persistent, very much across the RTOs at the national
21 level.

22 MR. DOBBINS: Are you able to make choices
23 whether to proceed or not to proceed coming out of the
24 SIS phase based on the information that you currently
25 receive from that?

1 MR. MARTINO: We as a company, we do what we
2 call very good educated guesses. We do a lot of work on
3 our side. Our experience, what we have seen, is that
4 not all of the information that's needed to make a
5 decision is made and presented at that point in time.
6 We also understand that, even if the information that is
7 presented at that point in time at the study phase, we
8 know that it's going to change, we know that it's
9 subject to change, and we know that we have seen very
10 large deviations, just like I said earlier, on cost
11 schedules and estimates.

12 So having said that, that puts a significant
13 burden on the interconnection customers to try to figure
14 it out or try to provide that visibility. But as far as
15 the information that's coming from the RTOs, as far as
16 what's coming from the TOs, at that stage, I don't think
17 it's enough, I don't think it's adequate, and I think it
18 could be a significant improvement going forward.

19 MR. DOBBINS: Thank you.

20 Mr. Gosselin, same question.

21 MR. GOSSELIN: I'd say in general, yes.
22 However, there are exceptions to every generality.
23 Where a system impact study where the group is still not
24 stable, right, where they present a system impact study
25 results to us, if it's going to get restudied we don't

1 know that, right, we don't know that something's going
2 to drop out and cause a restudy. But if we make a
3 decision at this point and then that changes
4 significantly on subsequent restudies, we're not able to
5 make it -- we either made a bad decision, we got lucky
6 or got lucky. Neither of them are good in this, right?
7 You don't want to have to run your work on being lucky
8 and you don't want to make bad decisions. So if it's a
9 final, final result, if there really is no more changes,
10 yes, there is sufficient information. But if not, it's
11 anybody's guess as to what might happen.

12 MS. RATCLIFF: So I wanted to dig a little
13 more into the idea of the balance between the accuracy
14 of the studies and the time it takes to complete the
15 studies. So I think what we've heard from the
16 developers here is that you guys were really interested
17 in accurate results, but I think the panels earlier this
18 morning talked a lot about getting through the queue
19 quickly and having these studies completed quickly. So
20 I was wondering for the whole panel, if you could just
21 talk a little bit to that the balance and whether it
22 would be possible to get more accurate results earlier
23 or if that would have a really negative impact on the
24 time it takes to proceed through the queue?

25 MR. ALIFF: So there is that balance between

1 that obviously. In the MISO process through the system
2 impact study phase, we are providing planning level
3 estimates. We expect -- what's an estimate for or
4 replacing a transformer or reconnecting in a line or
5 upgrading a line? We provide that information. But
6 until you get to that facility study phase where you
7 actually have someone in the field looking at the
8 equipment that actually needs to be upgraded, looking at
9 what the substation's actual design is going to be, you
10 can't really get to that accurate level that maybe the
11 developers are looking for.

12 And then starting that process earlier, has
13 tradeoffs as well, because you don't necessarily know
14 who's going to stay in that system impact study phase;
15 projects withdraw, maybe you don't need that. And then
16 now you have expense related to trying to develop that
17 accurate result that you have to throw out and you have
18 to start over again. So I agree there is that tradeoff
19 that you have to try to work through.

20 MR. GOSSELIN: Dean Gosselin with NextEra
21 Energy.

22 What we see is the big mover in cost is not
23 so much the facilities estimate, it's what's in that
24 facilities estimate, so what elements, is it
25 multiple-line re-conductorings, and we've got to add

1 dynamic VARs and we've got to add other shunt capacitors
2 all over the system and change out breakers, or do we
3 just have to do one thing? And that's what matters,
4 right, that stabilizes understanding what it is that
5 final groove that is -- the overloaded elements that
6 need to be upgraded through the system upgrades are
7 known. Once we know that, the rest moves not that much,
8 but that's the big deal for us. Thank you.

9 MR. KELLY: Paul Kelly for the transmission
10 owners. I would say our experience around the facility.
11 Study component has been that to get the accurate
12 information out we think that under the current MISO
13 process, it's a 90-day study, and when you're in the
14 definitive planning phase you get 90 days to do the
15 system impact, 90 days to the facility study. And we
16 think that that is probably the right amount of time if
17 the data quality was there, but I think the owners have
18 noticed that it can take awhile to negotiate through all
19 that to make sure you have all the data you need in
20 order to perform it.

21 And just contemplating what our
22 recommendation would be here, we would just want to
23 leave a thought that we think the study timelines are
24 appropriate. We're really focusing on the overall GIP
25 process, how can we squeeze some efficiency out of the

1 downtimes where you're waiting to actually initiate the
2 study, coming up with packages of information, so that
3 rather than spending the first five, ten days or more,
4 trying to figure out where all the right data is and
5 making sure everybody's on the same page, because it is
6 a balance among several parties, getting that upfront.
7 And the other piece just recognizing the project
8 management idea of do you want it fast, good, or cheap?
9 Pick two of the three. It's a real issue here and so
10 when you put multiple parties into that, that is also
11 another consideration. Thank you.

12 MR. MARTINO: I think we can achieve the
13 right balance between having timely accurate cost
14 estimates and construction schedules with shorter time
15 periods to study. I think what we need to do is we need
16 to create a process that allows essentially just that.
17 And what I mean by that is we need to have a GIP, an
18 interconnection study process, that is targeted for 12
19 months, a 12-month process so that interconnection
20 customers don't go into the queue thinking it is going
21 to take me five or six years to get something, and
22 therefore they crowd the clusters because they
23 understand they will not be able to do anything for the
24 next five or six years. If we limit the cluster the
25 study process to 12 months, the amount of study from the

1 time of instability in that, the study cluster would be
2 greatly reduced, which can reduce the cost schedules
3 issues that we face.

4 The other suggestion for improving the
5 process is having a smaller number of milestones.
6 Instead of having four, five, or six milestones during
7 the process, have three milestones in the process, one
8 for entry, one for exit, and one for making the
9 decision. Introducing more milestones in the process
10 introduces more uncertainty and introducing more
11 uncertainty introduces a likelihood of withdrawal,
12 therefore the complicating effects that we see on cost
13 estimates and schedules because those projects affect
14 each other. Those two can be achieved to mitigate that
15 issue.

16 And to conclude, I believe that involving
17 affected systems, involving the TOs earlier, moving away
18 from using the per-unit costs, getting away or using a
19 planning-level estimates, they should be gone away. The
20 entity should be providing estimate, accurate and
21 detailed processing at that point in time, because if we
22 keep using per-unit estimates or planning level
23 estimates the risk of having those change and impact the
24 projects are greater. So I think we can achieve a
25 balance, we can do that.

1 And fundamentally speaking, my last point is
2 that there needs to be a significant amount of resources
3 added at the RTO level to process the status. And
4 having said that, it can be done.

5 MR. McBRIDE: Thank you. We definitely
6 agree that there is a tension that we're hearing between
7 the desire for the study process to go faster versus the
8 desire for more accurate information in something like
9 upgrade cost estimates. We actually talked about an
10 aspect of this recently in making our own stakeholder
11 process, and we noticed that on the reliability planning
12 side we have kind of a sequence of development of
13 increasing accuracy of upgrade costs.

14 So we have a concept level for a project you
15 consider a concept, it's an order of magnitude-type
16 estimate, and that's plus or minus a hundred percent in
17 terms of what the overall cost would be expected to be.
18 The next stage is proposed, it's further along, that's
19 minus 25, plus 50 percent; then we have planned, minus
20 25, plus 25; and construction is something like minus
21 15, plus 15.

22 And to prepare a construction grade
23 estimate takes a lot of work for the transmission owner,
24 it's weeks' worth of work, if not months. It involves
25 site surveys and getting bids from equipment suppliers

1 and those kind of endeavors. In our stakeholder
2 discussions we landed on, at least in the feasibility
3 stage, that an order of magnitude estimate was -- our
4 customers told us that that would give them what they
5 needed at the feasibility phase. And we are going to
6 think through and discuss more with our stakeholders,
7 maybe using more of these bandwidths as we go through
8 the project completion steps.

9 MR. RUTTY: I think I definitely agree with
10 MISO down at that end, that to provide the right balance
11 of the cost estimates and the study results with what
12 the interconnection customer needs is key; to rush
13 through it and give them something doesn't make sense.

14 So again, the way the ISO works is we have
15 the two-phase study process, granted it's a two-year
16 process. I know Omar would love to have the one-year
17 process. But with 125 projects coming in cluster 9, it
18 just doesn't make sense to go out and do detailed
19 analysis in the field and what it would take to give a
20 phase II result at that point. We've come to a good
21 balance to provide per-unit cost at that point. Allow
22 them ample time after the studies are done to decide if
23 they're going to move forward. Do they have a PPA
24 opportunity, Power Purchase Agreement opportunity? Are
25 they going to be able to get financing? Do they have

1 their sites fully secure? It gives them time to adjust
2 as well. Not everybody that comes in our door is ready
3 to be moved at a year pace, And so that balance has been
4 struck in California ISO.

5 I do agree with Omar that bringing the
6 affected systems in very early is very important, and
7 we've adjusted recently to do that. I'm not sure I
8 could add any more than that at this point.

9 MR. VAIL: So PacifiCorp, not being part of
10 a regional ISO, I think there's a couple points that I
11 would make. It's certainly a challenge to hire really
12 good technical talent. But a PacifiCorp standpoint is
13 we are processing these generation interconnection
14 requests. The dates are very important to PacifiCorp,
15 we will meet our dates. If we don't have enough staff
16 available in order to meet those dates, we will contract
17 and augment our staff with consultants as well.

18 But it's important to note the cost of
19 going outside of the company can be dramatically higher
20 than inside the company. We have some pretty much
21 dedicated staff to the interconnection review process,
22 and they tend to be some of the highest-level experts
23 that we do have, because again, what you're doing is
24 bringing up this generation on the system, is doing a
25 reliability assessment. So you want to be careful not

1 to have too much volume through them and also you don't
2 want to contract too much of that work out. Outside
3 consultants may not have the same familiarity with the
4 system.

5 And I think there is a really fine balance
6 between that accuracy and detail, and I talked a little
7 bit about what's that communication upfront and really
8 trying to understand what level of detail do you need at
9 that project scoping? Because I think to Steve's point,
10 we have a real mixture of people that come in the queue,
11 and it's great when we have a very motivated,
12 sophisticated developer that already has their plans
13 laid out. I totally understand at that point wanting to
14 hit the ground running, and it's absolutely critical
15 that we as a transmission provider try to meet those
16 customer's expectations. We have a lot of customers
17 that really are putting their toe in the water, and I
18 think it makes a big difference. I would hate to put
19 exacting processes in place, because it isn't
20 necessarily a one-size-fits-all. And out of all of the
21 requests that come through PacifiCorp's queue, the
22 majority of them are not large or sophisticated
23 developers. So something to keep in mind.

24 MS. RATCLIFF: Thank you.

25 MR. JACKSON: Mr. Rutt of CAISO has

1 frequently referenced CAISO's study approach and how it
2 provides interconnection customers with a cap for
3 interconnection and network upgrade costs. Are there
4 any other frameworks under which these costs or caps are
5 based on study estimates? And if so, how do you account
6 for these studies?

7 MR. ALIFF: I guess I'll start. Tim Aliff
8 with MISO. So we do not have cost cap, per se, like
9 California ISO does. And we kind of see that as
10 shifting costs from the interconnection customer to the
11 transmission owner and ultimately the ratepayer having
12 that from a cost perspective I think you also touched on
13 the phase study approach, that is something we have
14 looked at implementing as part of our queue reform as
15 well.

16 MS. RATCLIFF: Can I ask a quick followup to
17 Tim? You said earlier in your introduction, you talked
18 about the 25 percent cost overrun number. I just wanted
19 to ask, that my understanding is that's not in place
20 when it comes to restudies and people dropping out of
21 the queue ahead of you. Is that the case?

22 MR. ALIFF: So it implies that the system
23 impact study results are different from the facility
24 study results. So it may or may not apply there in the
25 restudy, depending on what phase that restudy had

1 occurred.

2 MS. RATCLIFF: Thank you.

3 MR. JACKSON: Just a followup to Mr. Rutty
4 on your phased approach. In instances where the actual
5 cost are more than the phase estimate, how do you all
6 deal with those situations?

7 MR. RUTTY: Well, like I had mentioned
8 earlier, if the phase 1 sets the cap, original cap,
9 phase 2 goes above that, the transmission owner upfront
10 funds that payment. It should be stated here that our
11 ratepayers ultimately pay for all of the network
12 upgrades that go into our system. So if an IC ends up
13 paying for something, they're refunded by the
14 transmission owner over a five-year period or sooner
15 than that. So ultimately all the transmission upgrade
16 costs go to the ratepayer in California.

17 So, I mean, that's a distinction that
18 probably should be thought about as other folks are
19 trying to implement something like this. It's
20 different. But the bottom line is if it does ultimately
21 go above the cap, the transmission owner picks up that
22 delta and they put it into our transmission access
23 charge at that point.

24 MR. JACKSON: Thank you.

25 MR. DOBBINS: Did anyone else want to

1 comment?

2 Mr. McBride.

3 MR. McBRIDE: If I may? I do want to follow
4 up on what Stephen said. I think the ratepayer
5 component is critical in evaluating each different --
6 comparing each process. If -- we're talking today about
7 looking for best practices, and we just need to make
8 sure we're identifying what are the components of each
9 design that actually will support and then make it work,
10 and I think the ratepayer support makes a very big
11 difference to the overall California process. So I
12 think it's important to bear that in mind. As I said
13 earlier, in New England we do not have any ratepayer
14 support of interconnection upgrades, they're all through
15 the interconnection customer, and so that puts us at a
16 very different starting point.

17 MR. DOBBINS: Mr. Kelly?

18 MR. KELLY: Paul Kelly with the MISO
19 transmission owners. I think I would just follow
20 through with what Alan had said there, that within MISO
21 it is not refunded. So that would be more of kind of
22 the regional differences and to pick back up on that
23 there, I think this would be a great example of there
24 are certain things that support the philosophies and
25 methodologies that are used here, but this would be one

1 where that concern, as stated earlier around where do
2 you put the costs that comes to the network, and in MISO
3 the stakeholder process those that have participated in
4 have made the decision, that for interconnecting
5 customers that's going to be something they would have
6 to bear the cost of that analysis.

7 Now, there's -- outside of the scope of
8 that there's certainly questions around how many years
9 out is the study, and when do you draw the line about
10 how a particular upgrade may be needed in the future
11 versus whether you need to get that on the system now.
12 But I just thought that was important to point out that
13 that balance is constructed differently. But I think it
14 goes to the question that Commissioner Clark had earlier
15 today of just what are those driving differences that
16 would say this one needs to be maintained and do
17 something? Thank you.

18 MR. DOBBINS: All right. If there aren't
19 any more comments on this, we'll move on to contingent
20 facilities, and make this the last topic area. And this
21 is a question for the transmission providers. What is
22 the process for identifying those facilities that are
23 relevant to an interconnection customer for inclusion as
24 a contingent facility and its GIA and those which are
25 not? And then what are the challenges in identifying

1 and in listing the appropriate facilities?

2 MR. ALIFF: So the process for identifying
3 the contingent facilities that would go through the
4 interconnection involves the generation resources
5 impacts on those facilities, or whether those facility
6 are needed for that interconnection to occur in a
7 reliable manner. For example, our multivalue projects,
8 that I mentioned earlier today, is a contingent facility
9 for quite a few of our interconnection agreements,
10 especially in our west most part of our footprint.

11 As I said before, those were implemented to
12 ensure that large amounts of megawatts could
13 interconnect into the system at a later date, and we're
14 working through that process. So as far as some of the
15 technical challenges, identifying what the impact, the
16 criteria related to when does a resource actually impact
17 the facility, that can be debated and discussed. On
18 what level, whether it's distribution factor, whether
19 it's megawatt criteria, and those types of things that
20 could be discussed further and how those are impacted.

21 MR. DOBBINS: Mr. McBride?

22 MR. McBRIDE: Our process sounds very
23 similar to the Midwest ISO's. It's something that
24 prevents itself through the study process. In New
25 England we do have an overall transmission project list

1 that would be the defining list of what upgrades have
2 already previously been identified. And those could be
3 either for reliability upgrades or for other generation
4 upgrades.

5 And so if it's identified in the study and
6 then noted in the interconnection agreement as
7 appropriate, if it's a reliability upgrade in pretty
8 much all cases, that's going to be expected to go
9 forward. There may be cases where the interconnection
10 customer has to pay to accelerate a reliability upgrade,
11 that has happened on occasion. If it's a contingent
12 upgrade to another generator's upgrade, then we do note
13 the circumstance if that generator withdraws it doesn't
14 move forward, the upgrade can become that next
15 interconnection customer's responsibility. But that
16 would have been communicated to them through the process
17 through the interconnection development agreement.

18 MR. DOBBINS: And Mr. Vail and Rutty, unless
19 your process varies from the other two, I'm going to
20 just ask a question to Mr. Kelly. What role does the
21 transmission owner play in identifying contingent
22 facilities?

23 MR. KELLY: Paul Kelly for the transmission
24 owners. So I would just point to maybe the local design
25 requirements in recognizing that each of the owners is

1 going to have a specific design requirement on the
2 system. But as far as identifying the contingent
3 facilities, that's really, from my understanding, in the
4 purview of the transmission provider.

5 MR. DOBBINS: Thank you.

6 And Mr. Gosselin and Martino, I'd going to
7 ask you this last question of this panel. I'm going to
8 ask you to keep your responses to under a minute just in
9 the interest of time. How and when are you generally
10 made aware of contingent facilities that may affect your
11 project? And is it made clear to you why and how these
12 projects may affect yours? The and that last piece is
13 what I'm most interested in.

14 MR. GOSSELIN: So generally we're made aware
15 that incurring a system impact study process where they
16 said, "Okay, these other facilities have to be in place
17 prior to you coming on line and they have been allocated
18 to generators ahead of you in the queue, and if the
19 generators don't move forward or suspend and if you want
20 it you're going to have to be responsible for it." It's
21 been okay, it hasn't hindered us or created any real big
22 failures. But we've had a recent one where I think Cal
23 ISO has changed their process that say any facilities
24 that were ascribed to earlier queues that haven't come
25 on line, you may be responsible for those costs. And

1 now it's an open liability, I don't know how we're going
2 to handle that yet. Thank you.

3 MR. MARTINO: Sometimes we never get the
4 response on the contingent facilities. In fact, this is
5 a significant issue for our company at the seams,
6 specifically in MISO and PJM. In that case, as you may
7 be aware, we had operating projects there and there were
8 no facilities that were required for the interconnection
9 of our project, nor the interconnection for many other
10 projects. But in that case, there was a lack of
11 connection between MISO and PJM which resulted in
12 congestion at the seams, and the only result to resolve
13 that congestion was actually the interconnection group
14 funding 50 or 60 millions of dollars of upgrades. And
15 we feel that's very unfair, very unjust, and is simply
16 not an integration process that would be reasonable. So
17 the identification of contingent facilities has been an
18 issue for us at the seams.

19 In the actual footprint in the case of MISO,
20 the problem that we have there with -- I think it is
21 really a viability question, a viability issue, a
22 financeability issue, is that MISO's many contingent
23 facilities sometimes do not make any sense for the
24 project, but they are listed on the LGIA. And the issue
25 with that is when you try to finance the project, the

1 risk and the uncertainty for these contingent
2 facilities, even though they don't make any sense from
3 the reliability perspective, but they are just listed
4 there because they are from prior queues, makes matters
5 very difficult for interconnection customers. So the
6 message there is that for our experience, for our
7 company, facilities at the seams are an issue of lack of
8 correlation and a lot could be done there to hold
9 congestions, of assets, and at the level of MISO
10 reducing the contingent facilities to more reasonable
11 levels would be adequate.

12 And just to close, we think we can do that
13 by proposing the integration, the GIP integration,
14 focusing on short-term status, and having the complete
15 integration, like CAISO does, on the transmission
16 planning side where the RTO would take a look at the
17 number of the longer term and as well as the integration
18 of economic studies as well.

19 Thank you.

20 MR. DOBBINS: Once again we want to thank
21 all of there panelists for their participation. We're
22 going to take a short five-minute break and reconvene
23 for panel 4 at 2:20, 2:22.

24 (Laughter.)

25 (Whereupon a short recess is taken.)

1 MR. DOBBINS: Again, we are going to ask the
2 panelists once again to introduce themselves and make
3 either their prepared remarks which were submitted to
4 the docket or indicate the one or two most important
5 points they would like to make today. Please keep your
6 remarks under two minutes. We have this very nice wood
7 clock up here we're keeping track of time with, I know
8 some of you have seen it already, which we will use to
9 let you know how much time is left.

10 Please begin on the left. Mr. Aliff.

11 MR. ALIFF: Thank you again. I'm Tim Aliff,
12 director of reliability planning with MISO. Again, my
13 purview involves the interconnection, generation
14 interconnection processes. And thank you to the
15 Commission and the Staff for allowing me to speak on
16 three of these panels. So it's my third and final one,
17 so I won't have any more opening remarks after this.

18 Specifically, for this panel, coordination
19 is very important. Coordination amongst neighbors to
20 the RTOs and transmission providers; and then
21 coordination amongst standard connection customers and
22 transmission owners as well.

23 So that is something that MISO has worked
24 with. We have worked with some of our neighbors to
25 develop those processes and procedures, and we continue

1 to look forward to being able to do that with other
2 areas of our footprint. One of the things related to
3 coordination to Omar's comment about the MISO's process,
4 actually on Tuesday, a couple days from now, we are
5 going to discuss the very concerns that he brought up
6 about the contingent facility in our interconnection
7 process task force. So we are listening to our
8 customers, and I did make sure that Omar was aware of
9 that and look forward to his feedback, as well as others
10 that participated in the MISO stakeholder process
11 related to that.

12 So that's all I have for my comments. Thank
13 you.

14 MR. ANGELL: Dave Angell with Idaho Power
15 Company. And again thank you for allowing IOUs to
16 participate in these proceedings as well.

17 With regard to this particular topic,
18 coordination with effective systems is less clear in the
19 OATT today and the tariff, and I think there's an
20 opportunity to clear that up just a little bit. From
21 two perspectives: One being a utility dealing with an
22 interconnection customer and affected system, oftentimes
23 those affected systems have different standards,
24 different expectations than we have as a particular
25 utility. So whether they're different standards, and

1 all utilities have pretty fair reasons for the standards
2 that put in place. So trying to coordinate that effort
3 is complicated. Being on the other side,
4 interconnection customer is trying to interconnect with
5 another utility. And being an affected system you have
6 no relationship with that interconnection customer, yet
7 there's an expectation oftentimes that that utility will
8 have that affected system deal with the interconnection
9 customer. So some clarity around that would be useful.
10 And there are portions of the tariff where it appears to
11 imply that there should be a relationship between the
12 affected system and the interconnection customer, but
13 it's truly not spelled out. Those are my opening
14 remarks. Thank you.

15 MS. AYERS-BRASHER: My name is Jennifer
16 Ayers-Brasher. Again, thank you for letting me
17 participate in the second panel and holding this
18 technical conference.

19 As I mentioned this morning, improved
20 accuracy, accountability and transparency is needed.
21 And improvement in those areas can reduce the impact on
22 generators and I think, create a better balance.
23 There's been mentioned today that generators have
24 brought a lot of these issues on themselves, by
25 withdrawing from the queue and causing those restudies

1 and some of those issues.

2 But it really is a balance. If we can get
3 earlier, more accurate information, they're going to
4 withdraw sooner; if there's information available to do
5 more analysis ahead of time, that would also help as
6 well and reduce withdrawals and reduce them in the later
7 stages where there's the most impact.

8 There also needs to be more accountability
9 for the studies. Currently, in some areas we're paying
10 higher deposits, higher milestones, and yet if there's
11 errors in the study that are outside of our control,
12 it's not having to do with our information, we're still
13 the ones left paying for those. And it's most impactful
14 to the design of the interconnection agreement, we're
15 building the project and then we see additional costs
16 later on. It's still harmful in the process, but at
17 least we can work with that, and improve communication
18 and coordination as well. Those are my opening
19 comments.

20 MR. BARR: Thank you. Good afternoon. My
21 name is Dan Barr. Thanks for the opportunity for
22 allowing ITC to provide comment. I work as a principal
23 engineer in system planning at ITC. We're working with
24 generator interconnection for about the last 12 years.
25 As the nation's largest independent transmission

1 company, we like to think we've been successful working
2 with interconnection customers and MISO to achieve the
3 large growth in wind generation within the MISO
4 footprint. With the current incentives available to the
5 developers for renewable energy like production tax
6 credit, wind generation capacity will continue to grow,
7 processing that increasing number of requests will be
8 difficult, it will be exceptionally difficult through
9 the existing MISO queue process where a significant
10 number of requests are competing for dwindling
11 transmission capacity in the areas, as well as those
12 entities. If the goal is effective processing of the
13 queue, uncertainty needs to be minimized in the study
14 process. Uncertainties in the process lead to wasted
15 time and effort and restudies, and restudies are the
16 greatest impediment to effective queue processing. Just
17 to highlight a couple of the items that we sent in in
18 our written comments, most importantly, we strongly
19 support MISO's development of three separate, sequential
20 study phases separated by off-ramps or decision points
21 that were proposed in MISO's queue reform under Docket
22 No. 16-675. As part of that three-phase study process,
23 we also recommend incorporation of the cash-at-risk
24 milestone based on the cost of network grades that was
25 discussed a little bit earlier today. We also

1 recommend, as was heard earlier today, providing
2 interconnection customers with transmission models early
3 on to incentivize judicious choices in points of
4 interconnection, and allow them to do their own
5 feasibility analysis, putting the work in the hands of
6 the interconnection customer, giving them some
7 responsibility seems to make a lot of sense.

8 We also encourage RTOs and ISOs to take
9 advantage of existing information that they have and
10 provide to interconnection customers. There's a wealth
11 of information and facilities studies, cost estimates,
12 taken for us, several years, and there's also access to
13 real cost information for network upgrades. So, for
14 example, you could take a history of Greenfield
15 substation costs by voltage class, take all the actual
16 costs, and post them on the transmission website.

17 And then finally, we encourage FERC to
18 continue to allow individual RTOs and ISOs to address
19 the issues within their own respective stakeholder
20 processes. There's important differences within the
21 RTOs and ISOs, and we think they're best equipped to
22 deal with those through their stakeholder processes.

23 Thank you.

24 MR. HENDRIX: Good afternoon. Charles
25 Hendrix, Southwest Power Pool owner, manager of

1 generator interconnection studies.

2 As far as coordinating affected systems,
3 that is the challenging aspect. We've been working with
4 our neighbors, we still have some work to do on that.
5 One of those is we're dealing with our large queue and
6 speculative requests and now you're also having to deal
7 with affected systems and speculative requests as well.
8 So it's a challenging aspect. Withdrawals are primary
9 reasons for restudies of length of time it takes to
10 complete the interconnection process. We believe that
11 restudies are necessary on occasion to -- not build
12 unnecessary projects, but we believe there is too many
13 restudies occurring due to withdrawals. We think the
14 interconnection rules and procedures, we should further
15 reduce the incentive to engage in speculative requests.
16 Right now our process has to relook after the impact
17 study so that we had the restudy built in as a -- time
18 to withdraw, but we still see speculative requests going
19 into the facility study. As I said earlier, we have
20 7,800 megawatts going into the facility study in our
21 last facility study cluster.

22 After the impact study, we're allowing the
23 customer to withdraw and get their full refund back,
24 they can change the size of their interconnection
25 request and they can make any other modifications as

1 they see fit. Because the problem is their customers
2 haven't taken advantage of this option to direct a
3 facility study, and so we would like to see more
4 restrictive rules for nonrefundable deposits in that
5 department. Thanks.

6 MR. KELLY: Good afternoon. Paul Kelly with
7 the MISO transmission owners. I'm thankful again to
8 have the opportunity to participate on such a panel.

9 In looking at the issues in this particular
10 panel, around affected systems, I've heard the three C's
11 of communication, clarity, and coordination, and the
12 owners would support that. I think in looking at
13 working -- and particularly with affected systems, we
14 make the recommendation -- or I'm trying to develop very
15 clear flowcharts that kind of show timelines, I think it
16 was a great point that was just made that when you're
17 dealing with your own speculative projects in the queue
18 and end up working with somebody else, that can be a
19 mighty undertaking. But in those downtimes where there
20 is some capacity available and people's schedules trying
21 to work with through the major entities that you can,
22 and so that way you can also give notice to
23 interconnecting customers, "Here's what the timelines
24 tend to look like between our organization or our RTO
25 and another organization." Also as -- related to what

1 should generate the need to restudy, we would recognize
2 the flexibility's value. As mentioned in the past
3 panel, we wear multiple hats for many of the owners. At
4 the same time, though, when it comes down to a
5 reliability analysis, that once reliability's impacted,
6 that needs to be based on reality. So if there's a
7 change in the ability of that generator, depending on
8 whatever is adjusted, if it needs to be restudied, then
9 we fall down on saying yes, we think that also needs to
10 be upheld.

11 And then finally just getting back to the
12 point around I think a lot of the discussion we heard
13 today was encapsulated in a lot of the reforms that MISO
14 has proposed at the end of 2015. And so I think what I
15 had just heard here from Dan regarding the three
16 sequential studies and pairing that with milestone
17 payments that allowed interconnection customers to
18 increase their commitment to the process, as well as the
19 transmission provider to increase their commitment to
20 the next restudy, we think that was the appropriate
21 balance and we think that would be the right solution
22 there. Thank you for the time.

23 MR. MARTINO: Good afternoon again. My name
24 is Omar Martino. I am the the director of transmission
25 strategy with EDF Renewable Energy. Thank you again for

1 allowing me to speak with this panel.

2 Our view, that coordination is vital to an
3 effective interconnection process, and a coordination
4 between RTOs is vital between different regions, and as
5 well as coordination with affected systems. From our
6 experience, affected systems is a real concern for EDF
7 Renewable Energy. The matter of the fact that a
8 generator cannot even move forward through the
9 interconnection process, through the interconnection
10 standard, and execute an LGIA where the affected system,
11 timing and cost schedules of the upgrade are simply not
12 known at that time. We also want to point out that
13 there's a significant gap in the Commission's
14 integration policy for non-jurisdictional entities. A
15 number of non-jurisdictional entities either don't get
16 addressed or they don't get incorporated or are
17 participating in the planning process or integration
18 process, and essentially they can put a commercial
19 viability of a project at risk. And I believe that's an
20 issue that is a serious enough issue, and the Commission
21 should require measures in the tariff to remedy the
22 problem.

23 The second set of comments I want to say
24 here is there are a number of different areas where I
25 believe we can improve and a number of different items

1 we can accomplish to improve the process. You have
2 heard me indicate in the past that I think I really
3 believe having a shorter interconnection status can
4 alleviate the process, we should go for a 12-month
5 process, we should allow interconnection customers to
6 fund and build interconnection facilities, as well as
7 transmission facilities. We should provide reasonable
8 modifications to the interconnection facilities, to the
9 generation modifications, I mean by turbine changes.
10 Those should be more standardized -- COD extensions of
11 generators, as well as there's a significant need to
12 limit the restudies.

13 And my last point is while CAISO has done
14 this, they have precisely eliminated the restudy by
15 having an annual assessment, and they also have a very
16 flexible policy on extending the COD. Because we
17 believe strongly that should be standardized across the
18 multiple RTOs in the regions.

19 Thank you.

20 MR. NAUMANN: Good afternoon. Steve
21 Naumann, vice president, transmission and NERC policy
22 for Exelon. I can't really see the clock, so someone
23 give me a heads-up.

24 On the coordination issue, there's been a
25 lot said, but I'd like to reiterate something Mr.

1 Martino said earlier, that others have, they've asked
2 that congestion, which has not gotten as much discussion
3 here as reliability, be resolved both existing and new
4 -- this continues to be a challenge, and especially on
5 the seams, and especially seams between RTOs. You heard
6 Mr. Martino talk about the upgrades they had to pay.
7 And there's a tension between what's called as-available
8 interconnection service and later the as-available
9 becoming unavailable and the customer not being happy
10 and the harm to existing customers from taking the
11 headroom with the understanding that new customers
12 eventually become existing customers, and the same thing
13 happens to them. We want a resilient system, and we
14 need to do that analysis, especially on the seams. One
15 of the issues we've seen is the congestion gets ignored
16 because there's a filter, a high-distribution factor
17 saying, "Okay, we got a 20-percent distribution factor,
18 you got to put 20 percent of the machine on the line.
19 Oh, it's only 15 percent. We are going to ignore it in
20 real time" -- don't care about the distribution packet.
21 And you got to look toward I think best practices, and
22 especially on the seam, of dealing with this issue, or
23 you're going to get kind of congestion, the customers
24 would be unhappy. Thank you.

25 MR. DOBBINS: Once again we want to thank

1 all of our panelists today for both their participation
2 and their remarks. Staff will now begin asking
3 questions. You may have heard me say before, we are
4 going to ask that you please limit your responses to
5 around a minute so other panelists have time to speak.
6 And apologies in advance if we're unable to hear from
7 everyone on every topic.

8 Earlier today I believe it was PJM who
9 talked about their process and that transmission owners,
10 TPs, and interconnection customers are all very involved
11 in communication throughout the process. And I think
12 someone else also referred to the time and resources
13 spent in the early stages on scoping. And RTO ISO
14 tariffs and the pro forma, their provision for scoping
15 meetings between transmission providers and
16 interconnection customers, do these scoping meetings
17 normally take place within the time frames established
18 in the tariffs? And is there appropriate information
19 exchanged during those meetings? And then sort of
20 compound question is: When does transmission owners end
21 up getting involved in the process? And is that the
22 appropriate time? And are there any challenges for
23 that? I realize that's somewhat a long question, so if
24 people want to go beyond the one minute, I think that
25 may be okay.

1 (Laughter.)

2 We'll start on the left with Mr. Aliff.

3 MR. ALIFF: So as part of the MISO process,
4 we call an ad hoc meeting where we pull together the
5 interconnection customers and the group transmission
6 owners and discuss the group and the project and move
7 forward. As far as the question is it within the
8 timeline, as I mentioned earlier, we are delayed so as
9 we kick those studies off, that is when we are moving
10 into that process. The interconnection customer also
11 has the ability to request those meetings prior to
12 entering the queue, to ask for details related to the
13 point of interconnection, to work with the transmission
14 owner, the MISO, on how to best submit their
15 application, the data required for that application. We
16 very rarely see that occurring from an interconnection
17 customer's perspective. But when you actually get into
18 the queue, we do have that process that moves through,
19 and that stays -- that's little more of a communication
20 we talked about earlier occurs through that ad hoc route
21 through e-mail and then also through our Web page as
22 well, making folks aware of that process.

23 MR. ANGELL: Dave Angell, Idaho Power.

24 Not being part of an ISO or a RTO, I don't
25 know that we have the same sort of issues, but with

1 regard to setting up scoping meetings with the
2 customers, they are typically held a little bit later in
3 time at the customer's request rather than the
4 utilities' request. We're able to, but oftentimes they
5 are delayed by the customers themselves. As far as
6 information exchange, so we do focus as much information
7 as we can on our website about process and have
8 essentially a handler deal with the interconnection
9 customers right up front with quite a bit of exchange of
10 data prior to that scoping meeting so we can have an
11 effective scoping meeting, so I think that
12 communications even prior to the scoping meeting is
13 critical for a good information exchange.

14 MS. AYERS-BRASHER: I think we find that the
15 scoping meetings occurred, sometimes they are delayed if
16 the queue is delayed. But we are sent meeting requests
17 and we participate in those meetings for our projects.
18 One of the things that probably would be useful is only
19 the affected systems were included in those early on so
20 that everyone is aware that there is that impact and
21 that effect, and maybe those are even looked at sooner.
22 But the meetings are occurring, and generally within
23 time frames where we know about the delay if there's a
24 delay to the process.

25 MR. BARR: I think in general MISO does a

1 pretty good job of shepherding interconnection customers
2 through the scoping meeting. They're generally very
3 brief. Some of the transmission system in the western
4 MISO, there's a lot of different pricing zones, there's
5 a lot of different owners of transmissions, so a lot of
6 questions are: Well do you own that? Is that yours?
7 How much is that rated? So it's all very preliminary
8 information, and again it's a pretty quick process and
9 pretty basic.

10 MR. HENDRIX: At SPP it's also a pretty
11 quick process. We -- a typical window, this last one we
12 had 70 requests come in. So typically we'll send out
13 messages, e-mails, saying: Who wants scoping meetings?
14 Once we have questions, we'll initiate the scoping
15 meetings and we make sure that that is available to all
16 of the customers. A lot of our customers have been
17 through the process many times, so they're well-aware.
18 But we're always open to having the scoping meetings and
19 we will initiate when we need to.

20 MR. KELLY: Paul Kelly with MISO
21 transmission owners.

22 I think given Tim and Dan's extensive
23 responses here, I think there's enough said there.
24 Thank you.

25 MR. MARTINO: We don't really see -- this is

1 Omar Martino with EDF Renewable Energy.

2 We don't really see the scoping meetings as
3 being an issue for coordination, for coordination
4 between transmission owners, transmission customers,
5 interconnection customers. I think when we discussed in
6 my opening comments about the need for better
7 coordination, the need for more effective -- and the
8 need for really resolving the congestion, it's more of
9 an issue not of the scoping meeting but more of the
10 coordination of the status. And more importantly, not
11 the coordination of the status but resolve issues into
12 actionable items, meaning that if there is congestion in
13 the system, if there is congestion at the seams between
14 MISO and PJM, if there is issues for new facilities or
15 for existing generators, there has to be a way, an
16 avenue, whether it's tariff or a policy, to actually
17 resolve that issue and make it into an actionable item.
18 And that's one of the concerns that we have, is that
19 there has been long-standing congestion in certain areas
20 in RTOs. And it seems like different RTOs use different
21 standards, and some of the standards are not agreed upon
22 between the very same RTOs, so nothing really gets done
23 on that front. There's also a concern of utilizing
24 different DFAX, or distribution factors. Some RTO may
25 use 5 percent, maybe MISO might use 5 or 3 or 20

1 percent, and PJM uses 10 percent. So there's a lack of
2 coordination in the actual -- for the major structure of
3 the studies and how things are even weighted.

4 And just to conclude, there's also a
5 fundamental concern of getting the TOs more engaged
6 earlier in the process and getting the affected systems
7 engaged earlier in the process. So the point I'm trying
8 to make here is the scoping meetings don't seem to be an
9 issue for us, but it's really the engagement of the
10 parties, and the actionable item that come after the
11 engagement of these parties that lacks unison.

12 MR. NAUMANN: Just briefly to pick up on
13 what Mr. Martino said, I mentioned earlier and he just
14 mentioned, on the seams the difference in the
15 distribution factor makes a huge difference as to
16 whether you even see an impact or not. And so you get
17 an interconnection, and as Mr. Martino said, there are
18 different policies on dealing with congestion, but the
19 fact is that, dealing with it after projects are online
20 and people have spent money and said "I'm not happy
21 now," but now we got a process to try to fix it, that's
22 a timing issue. It's a bad timing issue because the
23 facilities that are online and now have seen the
24 congestion have now, by the time it's resolved with
25 upgrades, have seen three, four, five, or even longer,

1 years of harm. So it needs especially on the seams
2 between systems, or between RTOs, it needs to be taken
3 into account up front. Now, as I say, someone who wants
4 the least-cost interconnection, and I'm going to take
5 as-available, and say, "I don't want to pay for these
6 facilities." Well, as I said before, the new customer
7 will sooner or later be an existing customer, will be
8 impacted by the other customer, and be unhappy. So
9 there needs to be a serious look at how congestion is
10 dealt with, the interconnection process up front, and
11 that's a coordination issue. The better coordination
12 you have, the better estimates, the better studies, and
13 the more you can do up front to eliminate that and have
14 a resilient system.

15 MR. DOBBINS: One thing I think has clearly
16 come out of today is dealing with coordination with
17 affected systems. Mr. Martino just indicated that
18 coordination with affected system he would find helpful,
19 and I guess EDF would find helpful. What are the
20 challenges associated with affected systems,
21 coordination, and what are the clear areas or manners of
22 improvement? And we'll start once again on the left
23 with Mr. Aliff.

24 MR. ALIFF: Yes, thank you. Tim Aliff again
25 here. Some of the challenges related to that tend to

1 involve the different criteria as has been brought up,
2 and I'll address the 20 percent energy resource
3 interconnection service which is the MISO criteria. And
4 that is defined in our business practice manuals, and it
5 also came from our stakeholders, it is something we
6 discussed with our stakeholders, and we also brought up
7 with our stakeholders last year and discussed with that.
8 So some of that comes from our stakeholders and, as
9 mentioned earlier, what the difference is in the
10 flexibility. And then also there's challenges in
11 interconnection request, meaning that if a customer
12 requests network resource interconnection service, what
13 does that mean outside of -- for example on the MISO
14 system, what does that mean outside of the MISO system
15 and what criteria is used to evaluate those resources?
16 So those are where the coordination items need to occur.
17 The flexibility in the timeline, we've heard there's
18 differing timelines from six months to a year to two
19 years. Which you have to make sure you're coordinating
20 through those processes, and we've set up a defined
21 schedule with PJM where we will coordinate on certain
22 time periods and make sure we are coordinated in that
23 process.

24 Thank you.

25 MR. ANGELL: From IOU to IOU, the standard

1 practices, per constructions, efforts mentioned earlier
2 about whether it was a ring bus or breaker-and-half
3 requirements, those are some of the issues we find with
4 the effective systems. And, again, when studying
5 projects, what assumptions, distribution factors and
6 those sorts of things, always come up. And there's --
7 it appears at this point in time, just working through
8 the FERC tariff, the transmission provider that's
9 working with them seems to have the responsibility to
10 work through and coordinate those issues. And if
11 there's some clarity that could be provided there, that
12 would be useful.

13 MS. AYERS-BRASHER: Jennifer Ayers-Brasher
14 from E.ON.

15 From our perspective, the affected systems
16 there just needs to be more coordination and studies
17 need to be run more often. The last one we had was done
18 initially a year ago, and then they did update it the
19 following year, and then after that we had -- our costs
20 for the impacting upgrades go from 5 million down to
21 2-1/2, up to 21 and then to zero. So -- and that was in
22 about a four- to five-month time frame. To just have
23 maybe better coordination, have studies done more often
24 so there isn't a long time frame, because I believe the
25 time frame initially, that year time frame, could have

1 caught some of those things earlier on. So it's a lot
2 greater in our project process to make those decisions.
3 And when it went up to \$21 million, that nearly was a
4 project-killer, and that's several years down the road.
5 And it would have been nice to work through that earlier
6 in the process. So just more coordination for us.

7 MR. BARR: In the interest of singing the
8 same song, that's basically a coordination or sometimes
9 a jurisdictional issue. But if there's adherence to
10 well-defined turnaround times, that would certainly
11 help. Outside of that again, just more of a
12 coordination issue.

13 MR. HENDRIX: Coordination can be
14 challenging with the different criteria, the different
15 assumptions, the different interconnection service
16 products where some provider may give essentially a
17 deliverability product with interconnection service, in
18 the challenge, how that analyzed for impacting on your
19 system. Whereas, we're as big as we are as a energy
20 resource flavor to its queue. So just trying to mesh
21 those different products, it's a challenge.

22 MR. KELLY: Paul Kelly for the MISO
23 transmission owners.

24 I just point out that in the current MISO
25 GIP, we're in the pre-queue process, MISO publishes a

1 contour map to get in a sense of this is where the
2 saturation is in the system and this is where you can
3 find capacity. Looking at affected systems, I think
4 obviously when you're starting to look at geography you
5 can get a sense of how close am I to another affected
6 system? And I think the recommendation from the owners
7 would be just try to give as much notice as possible to
8 those looking to interconnect depending on where they
9 kind of fall geographically, to have a sense of, okay,
10 if you're here it's very likely that you're going to
11 need to be working with the entities.

12 So we already talked about the scoping
13 meeting, but just recognizing that when you start to get
14 near another RTO's border, that they're likely going to
15 need to be involved. And as far as the owners are
16 concerned, we take the responsibility to make sure that
17 we are monitoring the other potential affected systems
18 because we always want to know how the changes are in
19 effect. There are some I don't want to call them
20 "failsafes," but there is active monitoring that is
21 taking place. I just would encourage, according to as
22 the panel has pointed out, there is more
23 coordination/communication in trying to get through
24 things like the flowcharting process, recommendations,
25 just as much known as possible so that interconnection

1 customers understand when I start to get to these areas
2 I'm likely to run into a little bit of the slower
3 process because now I'm going to be bringing two large
4 processes together to try to run in parallel.

5 Thanks.

6 MR. MARTINO: I agree because I think a lot
7 of the comments already describe my ideas. I think
8 definitely coordination is an issue. But I think I
9 would probably take it now to the next issue, which I
10 think that -- the reason coordination is simply not
11 happening is because we just don't address it from the
12 issue, which is RTOs they have different standards that
13 transmissions triggered and wherever there's congestion
14 and one RTO, there may be no congestion on the other
15 RTO, so nothing gets built because there's no common
16 sets of standards. And the interconnection process at
17 the right time and at the right -- the current state
18 simply does not address congestion. The integration
19 process allows for 20 percent threshold between the
20 identification of the facilities and the actual location
21 of facilities and the actual grid improvement that are
22 required for a particular process. Without lowering
23 that 20-percent threshold, without having common
24 standards between RTOs, there's going to be a perpetual
25 congestion issue at the seams. So I think the issue is

1 coordination, but the fundamental concern is really to
2 have a mechanism to have an avenue to incorporate
3 congestion and addressed into the interconnection
4 process. And we can do that by having a common set of
5 standards.

6 Thank you.

7 MR. NAUMANN: The only thing I would add to
8 Mr. Martino. It's more of a common set of standards,
9 it's not congestion, it's simply not necessarily
10 addressed at the interconnection stage. And therefore
11 when generation comes on it sees congestion or
12 eventually sees congestion, as new generation comes on
13 and now we've got a problem and you're a few years down
14 the road now you're relying on the regional and
15 interregional processes to fix the congestion after the
16 fact which is years after and people have been harmed.
17 So it really means something fundamentally changed in
18 the interconnection process upfront to be able to
19 actually deal with congestion.

20 And the second thing is, you need to also
21 deal with the customer who says, "Okay, I will be
22 perfectly willing to take the risk, but I don't want to
23 pay for a single upgrade more than I have to have the
24 reliability interconnection." On the other hand, that's
25 harming existing customers and those customers are

1 dealing with this fundamental issues and also the
2 fundamental disconnect between, "I will take my chances"
3 and the bid energy market, which doesn't recognize "I
4 will take my chances," it simply lets flow who can flow.
5 Now, you can change that and say, "I say I take my
6 chances, you earn the first office as soon as I see
7 congestion."

8 The point is, it should be addressed, but
9 this is not the incremental fix. This is something
10 major that has to be set up upfront and done right and
11 thought about how it's going to be done. Otherwise, and
12 I'll just give you a statistic, just last week in Zone 4
13 of MISO, you got notices of 3,400 megawatts of base load
14 generation retiring. You're going to keep seeing that
15 as the congestion harm occurs. Not that that is the
16 sole driver, or maybe not even the major driver, but
17 every additional harm adds to things like that, and
18 you're going to lose your diverse generation.

19 Thank you.

20 MR. DOBBINS: I have a question for Mrs. --
21 I apologize if I don't get this right -- Ayers-Brasher?
22 Thank you, you're very kind.

23 I think that the examples you provided was a
24 very interesting anecdotal example of swings which may
25 occur, if I understand correctly these things came

1 through to, I guess, were pushed by the interconnection
2 trying to coordinate with the effective system. Just to
3 give it more context, what sort of information were they
4 attributed to go from 21 million to zero as such as what
5 the coordination of models assumptions, dropping in and
6 out of the queue, what was sort of the rationale for
7 something like that.

8 MS. AYERS-BRASHER: Our understanding was
9 there were changes in the system. The \$5 million had
10 been there for over a year, and then it did drop down
11 based on some changes in the system. And then
12 unfortunately when the transmission was unable to assess
13 the actual upgrade that was needed, they then went from
14 two and a half to 21 million. The problem there is,
15 understand maybe that's the upgrade that's required, but
16 how do you go from that big swing -- and then it dropped
17 to zero because it actually turned out that the criteria
18 being applied was not the correct criteria for an
19 affected system, so then it went to zero. Now, that
20 upgrade, if it's necessary, is still \$21 million out
21 there, whether the system needs it or the next generator
22 possibly. But those big changes are very difficult for
23 projects to work through, especially when you're nearing
24 an interconnection agreement.

25 MR. DOBBINS: All right. Thank you.

1 Mr. Angell alluded to possible needs of
2 clarity in the tariff. The RTO and pro forma tariffs
3 provide guidance for coordination of studies in the
4 protected system. Is that guidance sufficient for
5 proper coordination?

6 MR. ANGELL: Yeah, with regard to
7 coordination I think the guidance is sufficient. How to
8 deal with disagreements is not covered at all. And with
9 the interconnection customer having essentially an
10 interconnection agreement with one party and then an
11 affected system, the interconnection customer may end up
12 with an agreement with them as well. And there's no, I
13 guess -- I don't know if there's any accountability for
14 the affected system with regard to time or cost. And it
15 seems like that might need to be addressed.

16 MR. DOBBINS: Would anyone else like to
17 comment on this in terms of if the guidance is
18 sufficient in the tariffs, in the pro forma? No. And
19 then before we move on from affected systems, do FERC
20 staff have any other questions on this topic?

21 MR. LUONG: Yes, I had a clarification
22 question regarding the distribution factor threshold.

23 Is it applicable to both synchronous
24 machines and asynchronous machines? And it is posted
25 anywhere on OASIS clearly what is the number?.

1 MR. ANGELL: The distribution factor,
2 basically not threshold distribution factor, are a
3 factor of the system where the energy will disburse
4 through the system and through a type of machine that's
5 actually operating.

6 MR. LUONG: I think when we mentioned about
7 congestion, you know, the way I understand the
8 distribution factor threshold is, you know, you can see
9 how much you impact on your distribution factor on your
10 transmission constraint, is it three percent or five
11 percent? So when you use that, you know, in order to do
12 that, right? So, just trying to see that, you know,
13 it's not like you have different number for the, you
14 know, regular, you know, synchronous machine resource
15 and for the asynchronous machine, you know, the
16 transmission provider use a different number and those
17 are available, you know, normally posted. So, I'm
18 looking at the ATC calculation. You know, you have that
19 kind of threshold and when you have congested, you know,
20 then we normally in our own way we call TLR, you know,
21 then that threshold is there and then in the West you
22 have unschedulked flow mitigation, you know, those
23 threshold is there. So I'm surprised to hear that the
24 threshold is really an issue, big issue, you know, in
25 terms of congestion for the interconnection.

1 MR. NAUMANN: First of all, the distribution
2 factors vary by transmission provider. As was said
3 earlier -- and I hope I'm not quoting out of context --
4 MISO has worked with their stakeholders and come up for
5 certain cases with a 20-percent distribution factor.
6 For those same kind of studies, PJM is five percent for
7 the lower voltage facilities and 10 percent for 500 kV
8 and above; that's a big difference.

9 Our view is 20 percent allows a whole lot of
10 congestion be put on the system. Now, TLRs for example,
11 that's in the operating frame. Again, the wire doesn't
12 care what the distribution factor is, the only
13 distribution factor is when you line up the transactions
14 or the generators that are going to be curtailed or
15 reduced. It's what threshold it is, which is a much
16 lower threshold, and then how much they end up being
17 reduced.

18 So, yes, there is that disconnect. But as
19 far -- each TP deciding what it should be, either
20 through its own process or through its stakeholder
21 process. We just feel 20 percent is excessive and is
22 one of the -- with respect to the stakeholders in MISO
23 who have come up with that, we just simply disagree. We
24 think that's excessive and has resulted, as I believe,
25 in congestion on the seams between PJM and MISO.

1 MR. MARTINO: I just wanted to add that
2 maybe the factors are established that they are the same
3 for different technologies, so they are the same for
4 different technologies but they are different according
5 to the TOS, and that's especially where the issue is at
6 the seams because we have different standards.

7 Just to add on to that, the congestion issue
8 really plays into the earlier discussion this morning
9 the need to create an operational model right. There
10 was a discussion, and I'm going to point to that in a
11 second when I can find it in my notes. But there was a
12 discussion where there was a need to create a model
13 where it actually mimics operational characteristics and
14 having these very different factors is essentially the
15 complete opposite. It allows for grade levels of
16 congestion into the grid, which obviously does not get
17 dispatched in real-time, that's where specifically wind
18 energy at the seams get curtailed very significantly.
19 And the importance of this matter for the wind industry
20 -- but on a different note maybe I will just leave it
21 there. I sort of lost my thought.

22 MR. KELLY: Paul Kelly for the MISO
23 transmission owners.

24 I just wanted to approach this congestion
25 question from a different aspect because obviously it

1 depends on the type of service that you're requesting
2 and the timing of where your project falls in and how
3 many years go by before the next project comes along.
4 So there's a lot in that aspect, and looking at it from
5 a reliability question in that when you go through the
6 interconnection process you're looking at reliability
7 assessment. I think the owners would be supportive to
8 the extent MISO wanted to reevaluate the philosophy
9 around how you get generators, and the reality is -- and
10 I think Steve is pointing it out -- depending on how you
11 set some of those levels around the distribution factor,
12 you can encourage the connection of a generator at a
13 much cheaper cost than you might incur depending on
14 where you set that threshold at.

15 Based on the notice in this particular
16 technical conference, I didn't want to try to overstep
17 on the congestion piece, but just to recognize that to
18 the extent your reliability assessment shows that you
19 need a particular level of upgrades based on how you
20 stress the system. Well, if you make that upgrade, it
21 can relieve the congestion, because you'll never run
22 into it because you designed the system, will allow that
23 power flow.

24 Thank you.

25 MR. DOBBINS: Are there any other comments

1 before we move on?

2 MR. MARTINO: I have one last.

3 MR. DOBBINS: Okay.

4 MR. MARTINO: The point I wanted to make
5 earlier was tied the congestion to the accuracy of the
6 results also. And I think -- and I'll talk in a second
7 but I think this is important -- this is important
8 because if we get to the point that we don't get
9 results, we have a very difficult time in financing
10 projects, so we have consequences down the streams.

11 So it is very important that we get our LGIA
12 on time and on schedule and have representation of cost
13 estimates on a certain schedule and so on that we talked
14 about earlier. But that the results are also accurate
15 in the sense that we don't get a set of the studies that
16 are not representative of system conditions, and
17 therefore financial investment entities simply cannot
18 rely on them or ask for more information. So that's
19 where the congestion piece actually ties back to
20 accuracy of results back to the generation industry.

21 MR. DOBBINS: All right. We're going to
22 move on now. I know there all other questions from our
23 staff here.

24 MS. RATCLIFF: Changing topics a little bit
25 from management issues I know we've talked a lot --

1 especially with MISO earlier -- about preventing
2 speculative projects from entering the queue. And I
3 just want to get a sense from the panel from different
4 perspectives on what the balance is between preventing a
5 project coming in that maybe has no chance of really
6 succeeding versus recognizing the project won't --
7 perhaps in Ms. Brasher's case -- that a \$21 million
8 upgrade automatically makes a project speculative in
9 some sense? So if we could just go around and talk a
10 little bit more about where that line should be drawn in
11 your opinion.

12 Thank you.

13 MR. ALIFF: So I guess I'll start. I heard
14 one of our stakeholders say that every project's viable
15 until it is not. So that is the concepts that can
16 change that and can change it quickly. As far as the
17 milestones, we had a thought, and we've heard from our
18 stakeholders on what that means -- I don't know that we
19 have the exact answer on what that is yet -- the idea of
20 it applying to the congestion seems reasonable because
21 if you're likely going to -- that's going to be the
22 outcome if you come up with a project with
23 several-million-dollar upgrades, that it's probably
24 going to be a point where that project becomes unviable
25 depending on how that would work out, so.

1 MR. ANGELL: The speculativeness of the
2 project is dependent upon where that project attempts to
3 site on the system. Again, when there's congestion and
4 if they're on the wrong side of that, any project
5 becomes speculative in that point in time. So how to
6 actually develop a standard pro forma tariff that
7 addresses that fine detail, I'm not sure how to do that.
8 But if we do come up with something, we'll put it in
9 comments.

10 MS. AYERS-BRASHER: I think we're trying to
11 reduce some speculation. There is that balance, more
12 information upfront so people can make a better decision
13 and based on that decision they know the congestion so
14 that they're not going to those places. We may have
15 made some different decisions on some of our projects
16 had we known upfront instead of dealing with it on our
17 back end and at a high cost.

18 So knowing that up front and being able to
19 do that -- and as generators become more sophisticated
20 we're also doing more and more of these things
21 internally so if the information is available we're more
22 able to do a lot more. That's not going to take care of
23 everyone; I think you'll understand that. But the more
24 information that's up front, and also in the first round
25 of studies the more information that's available so that

1 the withdrawals occur earlier, probably the better.

2 MS. RATCLIFF: Quick follow up with that.

3 When you say more information up front, are you speaking

4 about more information from the transmission owners.

5 But getting that meeting, getting more involved, the

6 facilities, could you be a little bit more specific?

7 MS. AYERS-BRASHER: Better access to cases,

8 both economic cases and the transmission-planning cases,

9 better understanding of assumptions, more accurate

10 assumptions in some cases, pretty much any information

11 that can help to make a better decision.

12 MR. BARR: I think in terms of viable

13 projects, it's hard to say you know you're not viable

14 from somebody passing judgment on it. Assuming that you

15 all are viable and assuming that you have to process

16 your queue, and assuming that at some point you have to

17 do a final study to determine what's needed for

18 projects, you're not going to want anybody in that study

19 group to drop out. So you have, let's say 1,000

20 megawatts study, the impact of one of those projects

21 dropping out is significant.

22 If you take it to the extreme, under the

23 current GIP, you could be a nonviable project in the

24 queue and your obligation financially from the point

25 that study ends under the current process is that your

1 only obligation is to fund the facility study.

2 So you fund the facility study, let's say
3 that takes \$20,000 for your project, you fund the
4 facility study, you go forward, you're still trying to
5 sell your project, you're the developer, you're pretty
6 sure you have a good project but you're not a hundred
7 percent confident. But your only stake in the game is
8 to provide that what we'll call \$20,000 for the
9 facility.

10 Continue to look for your project and under
11 the current process with the GIA, GIA takes 60 days
12 where you have 30 days to negotiate, you have another 60
13 days from the interconnection customer's perspective to
14 sign the GIA.

15 So let's say you take that and you put up
16 the entire clock: You take 30 days to negotiate, you
17 drag that out, you take another 60 days, and then you
18 circulate the GIA for signature, you sign the GIA. And
19 in the GIA there are payment requirements, one of those
20 payment requirements says provide a payment entered.
21 Another 30 days adds on there and you still haven't sold
22 your project.

23 So you don't really lose anything if you
24 don't make that payment but the process continues,
25 there's still other projects queuing in, there's still

1 doing other studies, so that 30 days go by.

2 Well, our policy is, as transmission owners,
3 we send a breach notice if you're 30 days late, so
4 there's another 30 days on top of it. So then after we
5 send the breach notice, then there is -- under the
6 tariff there's I believe 30 days for a cure. If you
7 don't cure by then, then you have to say you're trying
8 to cure. So you say you're trying to cure it. And then
9 eventually when you get 90 days after that time point,
10 then you GIA is terminated. In the meantime you've
11 still got this study queue progressing, you still got
12 other projects that they're basing their projects
13 successful reliability on your project and your upgrades
14 being there.

15 So if you back that out then somebody like
16 MISO is forced to do a restudy. So under the current
17 process there's problems inherent in the process. So
18 making sure that when you get to that final study that
19 none of those projects drop out is a pretty key element.

20 And I think that the proposal that MISO has
21 where you give you project two chances to drop out, and
22 when you get that second change you should be reasonably
23 certain that you project is willing to go forward,
24 you're willing to put your chips in the game. And if
25 that's the case then a lot of that restudy stuff should

1 go away, but that's not what we have today.

2 MR. HENDRIX: At SPP, we give customers a
3 lot of opportunities to view this information. We have
4 feasibility study, which is a \$10,000 deposit, pre-look
5 at the system; we have a preliminary impact study which
6 is a full-blown impact study that the customer does an
7 impact on the regular queue; and then going into the
8 definitive study there is the built-in restudy there.
9 So the customers have plenty of opportunities of what
10 they're getting into even after the interconnection
11 impact study.

12 So going into that interconnection facility
13 study for SPP should be a critical step. And that
14 should be the last chance when they put in that facility
15 study deposit that we know they're going to move
16 forward, but it just hasn't come to that yet so far.

17 Thank you.

18 MR. KELLY: Again, I think the comments have
19 been made. I'll say that rather than focusing on the
20 end of that process, maybe I think the question was
21 directed of, How can you discourage people from even
22 entering the queue if they have something speculative?
23 And I think earlier this morning we heard discussion
24 around if you can ratchet up the entry-level
25 requirements and try to have some natural barriers to

1 discourage. I don't mean to be a broken record, but I
2 would say the owners evaluated the proposal that MISO
3 put together, kind of had the right balance right now
4 because facing the opportunities to go in there and do
5 the feasibility study, get a basic sense, make a
6 decision, "Okay, do I want to move forward or not?" And
7 then once you start getting into those sequential
8 studies, because you're escalating the commitment
9 through milestone payments, we thought that was the
10 right balance and way to start to test it out.

11 I think reality is, one thing I'm hearing
12 throughout a theme today, is I'm not necessarily
13 requiring a particular timeline but at least give me
14 certainty I know how long it's going to take. I think
15 if you know you're going to go through a series of
16 restudies, we should have a particularity around that.
17 And the owners saw that has being very valuable that it
18 may not be the exact number of months that any
19 particular interconnection customer may want, but at
20 least you know, "Okay, there's a sequence of events, I
21 can plan my business, if it's a permitting issue I would
22 kind of have an window of opportunity that I know need
23 to start moving the other pieces of my project."

24 And the last point I would make is that, it
25 has been recognized that when an interconnection

1 customer enters a queue, they're not shovel-ready to
2 sell. They're also developing their pieces. And I
3 think that type of proposal that was put out there,
4 although tweaked and refined, it did recognize we're
5 we're trying to land several planes on the same runway
6 at the same time, and all of a sudden it's going to
7 become one viable project in the end.

8 Thank you.

9 MR. MARTINO: I think the question of
10 reliability really highlights the fact that the
11 interconnection queue is simply not working today. And
12 I say that because, right now, interconnection customers
13 enter the queue thinking that they're going to be there
14 five, six, or seven years in some cases, and by
15 extending these very large timeframes just by itself
16 puts viability on to projects just on the outset.

17 So blaming interconnection customers for
18 lack of viability is, I think, a very unfair statement
19 and I think the fundamental issue, which is queue
20 reform, that targets the new era that we're living,
21 which is competitive markets, the ability to integrate
22 into competitive market very quickly and get your LGIA
23 an agreement in place.

24 So having said that, we can reduce project's
25 viability by having the interconnection process that is

1 fast, that is expedited. And you heard me say earlier
2 that a 12-month process should be ideal. Currently, the
3 MISO process certainly is not working, and I can say
4 "certainly" because they're delayed, they're delayed by
5 over one year. So MISO is proposing to put more and
6 more milestones to the process, to increase viability is
7 simply not going to be a good measure. Increasing
8 milestones actually increases viabilities. We have to
9 have, not only a short process, but a very well-defined
10 short set of milestones to increase viability.

11 And the last comments is that we need to
12 start thinking of having a process that is somewhat
13 similar to what California ISO has. And to the extent
14 that, as much as I want a 12-month process, the fact is
15 that CAISO is the RTO that can get this done in 18
16 months or 24 months. I don't think many of the other
17 RTOs can actually say that. And that increases project
18 viability. As well as the California ISO has a very
19 flexible criteria in changing, changing COD's for the
20 project, something that many of the RTO's can -- one of
21 the RTO's actually go after interconnection customers
22 and cancel their agreements by changing the COD. And in
23 the case of CAISO, something as being in the
24 negotiations of the PPA, for example, would qualify for
25 a criteria to change that PPA to that COD. So if you

1 want to reduce viability, we have to have a short
2 process. We have to have very well-defined milestones.
3 We have to have a process that incorporates into the
4 transmission flow just like the California ISO does as
5 well. So those are the key elements.

6 MR. NAUMANN: Quickly, I don't know what
7 "speculative" is. I'm going to speak first as a
8 transmission -- generation owner and developer. We
9 would look at putting let's say new gas-fired generation
10 in PJM, it may have four queue positions. And we only
11 intend to go through with one, that's not speculation,
12 that's trying to get information on which is the most
13 viable. So maybe we can change the term. You start
14 getting that information and then you drop out. But
15 that's having multiple positions is not speculative,
16 it's the flexibility one needs but it does create,
17 because of the way the evaluation is done, there's
18 nothing that says, "Evaluate this because I'm going to
19 take one of four," they have to be all evaluated and
20 they're added. And, again, this goes back to I think
21 the conversation we had this morning and Commissioner
22 LaFleur asked about it, a lot of the time, the restudies
23 end up occurring because somebody at some point says
24 "this is too much" or "my project is not viable for some
25 other reason," and somebody drops out of the queue and

1 the cost now -- it has to be restudied for two reasons,
2 one, you may not need upgrades because you got somebody
3 out of the queue, two, it shifts the cost of those
4 upgrades to somebody else and they may not want the
5 metric.

6 The last thing about some of the California
7 process is understanding it's a single-state RTO. They
8 can do certain things on the costs of the upgrades by
9 putting them on the customers because that's where it's
10 going to go. A multistate RTO like PJM or MISO or SPP,
11 those things can get really controversial. So I think
12 you may look at what California does, I would say before
13 you put it into a multistate RTO, think of what other
14 reactions may occur.

15 Thank you.

16 MS. RATCLIFF: Great. Thank you.

17 MR. MONCAYO: I'd like to ask a question.
18 Earlier, panelists alluded a needed ability to clear
19 projects in the queue as appropriate.

20 How frequently have any of you been involved
21 in disputes involving GIA termination.

22 MR. DOBBINS: And while answering that,
23 please also let us know, are there clearer standards
24 with regards to what constitutes or what allows for a
25 GIA termination? And we'll start on the left.

1 MR. ALIFF: So MISO has filed for
2 termination of several generation and interconnection
3 agreements. And I think from a clarity standpoint
4 related to that, we have a provision that allows for
5 generators to go three years beyond their commercial
6 operation date, and if they have not achieved commercial
7 operation by that time, we have the ability to terminate
8 that generator interconnection agreement.

9 Now, there isn't a defined criteria that
10 says what makes this project the project to terminate or
11 not. So we err on the side that we terminate the
12 project in that standpoint. We did try discussing that
13 in our stakeholder groups last year. We didn't get a
14 lot of support for that. We got a few folks that were
15 supportive in developing a set criteria related to that
16 termination provision, but we don't have anything. Some
17 clarity around what is it, exactly three years and then
18 we terminate? Or has somebody done some level of detail
19 at that project in order to reach that level of
20 termination.

21 MR. ANGELL: Yeah, at Idaho Power we have
22 terminated projects. Failure to make payments obviously
23 would be a cause for termination. And then of course
24 attempting to -- well, basically not constructing and
25 achieving an online date given extensions that are

1 already available in the tariff.

2 MR. BARR: Just to add, we could have a very
3 similar scenario, as described earlier, we have had
4 probably two-three terminations as a TO with a three
5 party agreement with MISO and the interconnection
6 customer.

7 MR. DOBBINS: Were those all based on people
8 exceeding a commercial operation date by a certain
9 period? Was that the only reason?

10 MR. BARR: No, I don't know that we had any
11 of those. We had one that was tied up here for quite
12 some time and that was eventually terminated. We had
13 another that for whatever reason the customer was unable
14 to bring things together enough to push the project
15 forward. And then the other, I think, I'm at a loss for
16 cost.

17 MR. HENDRIX: And I think we've been
18 involved in the termination of several GIA's, the most
19 common is the nonpayment for construction of the
20 facilities. When the first milestone comes up, I mean,
21 a lot of the customers will go into suspension, so the
22 second-most probable terminating event is when the
23 suspension is up they don't ask us to resume
24 construction, so the payment and some suspension and
25 then recently in our most recent reform we did add a

1 requirement to build, make sure all the generations are
2 built at least within three years of the GIA commercial
3 operation date and the GIA. That has not been in effect
4 long enough to really determine anything from that
5 perspective yet.

6 MR. KELLY: Paul Kelly with the MISO
7 Transmission Owners.

8 I would just say that collectively as the
9 owners, I don't think we've had enough of these
10 situations occurred where we've gone forward with an
11 approved GIA, and things have been made, and then all of
12 a sudden somebody couldn't become commercially
13 operational. I may be speculating that, they're solely
14 addressed in post-conference comments, if that's
15 inaccurate. But I think the more-regular situation is
16 just kind of a situation where you get into the signed
17 GIA but the payment doesn't come and then it just
18 naturally terminates from that point forward.

19 MR. MARTINO: I think the termination
20 provisions really has to be looked at with respect to
21 the RTOs. When it comes to extension of COD's, in our
22 experience, there are a number of projects that are on
23 similar situations but they have been treated
24 differently. And I think that having a project with an
25 executed LGIA with interconnection and transmission

1 facilities built into the system, which other customers
2 can take advantage of and that price is terminated, I
3 think that's something that has to take us back and see
4 who should be reexamining the termination provisions in
5 the tariff. Something we would like to see, as I
6 mentioned earlier, is the COD extension criteria that we
7 saw in the California ISO where if you go past a certain
8 window you're not automatically terminating like in the
9 case of MISO that they're very concerned about the
10 three-year time period. You're active, including LGI
11 payments, network facilities, and transmission
12 facilities, but you're also pursuing a contract then you
13 can show that, I believe the California ISO does grant
14 extensions based on those facts. So I think that's a
15 gray area and I think we really need to reexamine it and
16 something I would like to see is consistency between
17 RTOs. I think it's unfair to that one RTO would have
18 termination criteria very different from another RTO,
19 that's something that I think should be consistent all
20 across the board.

21 MR. DOBBINS: All right. Thanks.

22 So that wraps us up for panel 5. There was
23 no break scheduled between, I'm sorry, that wraps us up
24 for panel 4. There was no break scheduled between that
25 and panel 5. So we're going to take five minutes to set

1 up for the next panel.

2 Okay, thank you.

3 (Whereupon a short recess is taken.)

4 MR. HERBERT: All right, let's talk about
5 energy storage, or electric storage resources as we've
6 been more affectionately referring to it lately. I like
7 to thank the panelists for coming to talk to us, the
8 audience for persevering to the end or showing up
9 especially for storage. Either way, it should be
10 interesting conversation.

11 We do have a relatively aggressive agenda
12 for this panel. We teed up five topics in the final
13 agenda, as you guys have seen. We'd like to allocate
14 about 10 minutes each to those. Kaitlin here will help
15 me keep on track, if we're over time on something, move
16 onto the next topic. But as Tony said earlier, if
17 people can keep their responses to about a minute each,
18 I would like to try to give everybody an opportunity to
19 speak on the panel. And again, apologies in advance if
20 we don't hear from everybody on every topic. But we'd
21 like to kind of try to cover the front as much as
22 possible.

23 So with that said, I'd like to thank the
24 Chairman and Commissioner LaFleur for showing up. And
25 without, I guess, further ado, we can go ahead and do

1 the introductions. As before, you'll have a couple
2 minutes. And we got this nice clock down here letting
3 you know when your minutes are up.

4 So, Dave, if you want to go ahead.

5 MR. EGAN: Dave Egan with energy
6 interconnection project with PJM.

7 Regarding storage facilities, PJM has had a
8 lot of experience over time starting with CAISO, with
9 flywheels, and now battery storage. We interconnect
10 these facilities using our generator interconnection
11 procedures. We also model them as a load, since they do
12 both activities and it's based on the inverter and the
13 power delivery and power receipt, not necessarily the
14 storage size of the battery that we study.

15 We allow for distribution level
16 interconnections to participate in our markets. Some of
17 the issues that we have on that, they'll get into
18 whether the storage facilities participating in retail
19 or wholesale and the timing of that, so one or the other
20 at any given moment. Combining of battery storage with
21 other generation fuel sources, we have no issue with
22 that. We treat, again the incremental increase in the
23 power output is what we would study, and we would also
24 again review the delivery power to the battery as
25 required.

1 MR. EMNETT: Good afternoon. I'm Mason
2 Emnett on behalf of NextEra Energy Resources. I also
3 want to thank the Commission for the time and attention
4 to this topic.

5 I think all of us are relatively low on the
6 learning curve of how to integrate storage, develop
7 storage facilities, integrate them on the
8 interconnection process, and then operate them on the
9 system. So I think it's great that the Commission is
10 taking the time to focus, not only on the
11 interconnection side, but also the market rule questions
12 that the Commission has out.

13 So NextEra has four operating energy storage
14 batteries in the PJM market, and we've got projects
15 active in development in all the other RTOs.

16 So in our experience in navigating the
17 interconnection process for the battery has really
18 informed our experience with the wind and solar side,
19 which, as Mr. Gosselin explained, well, several panels.
20 There are issues to deal with in terms of navigating
21 that process, the timeliness and accuracy of studies,
22 and the delay, and all that good stuff.

23 As we think about developing battery storage
24 as a large generation owner, we first wanted to
25 co-locate our batteries with the existing generation

1 projects to figure out where is that extra unused
2 capacity, or frankly even land rights, where can we go
3 and plop on an outset? And as a highly-controllable
4 device from a battery's perspective, we can control
5 anything. We can use the excess interconnection rights,
6 we can oversize the project and just never exceed our
7 interconnection rights. But as we've gone through the
8 interconnection process, typically the way the RTO could
9 consider our project is as an incremental addition. So
10 we get studies based on the total injection.

11 And what we would like to see for co-located
12 projects is to really focus on what it is that the
13 customer is requesting on the actual injection rights.
14 And so that's the main path that we have today and we
15 look forward to discussing all the other issues with
16 you.

17 MR. FERNANDES: Good afternoon. Chairman
18 Bay and Commissioner LaFleur, thanks for joining us.
19 And thanks to Staff for the invitation to speak and for
20 sticking around late on a Friday.

21 John Fernandes, policy director for RES
22 Americas.

23 Within RES's of 10 gigawatts of global
24 energy projects, we have about 100 megawatts of storage
25 that's in operation or under construction in four

1 different countries.

2 When I think about the strides that we made
3 within energy storage, especially over the past couple
4 of years, I think a lot of that has been predicated upon
5 the speed and accuracy of a storage plan. And I think
6 one thing we have ignored is the speed and accuracy of
7 the control platforms that sit behind the storage plan.
8 And it's those control platforms that set the parameters
9 within which storage will charge and discharge, fully
10 automated. And a lot of times we're frequently
11 developing plants to operate that charge and discharge
12 around net zero, not at a full discharge and not at a
13 full charge.

14 So I think as we consider that a little bit
15 more moving forward, especially inform system operators,
16 RTOs, and coming utilities, really on what is that
17 storage project going to be doing and what are the real
18 interconnection needs for that plan? So I look forward
19 to discussing that a little bit more today.

20 MR. GABBARD: Good afternoon. I'm going to
21 reintroduce myself.

22 My name is Dave Gabbard, I'm director of
23 electric generation and interconnection for PG&E. I'm
24 responsible for inter-connectional traditional renewable
25 and energy storage generation to PG&E transmission and

1 distribution system.

2 PG&E is in partnership with California ISO.

3 The stakeholders have put a significant amount of effort
4 into looking at the interconnection process for storage
5 generation to PG&E's wholesale distribution tariff and
6 California ISO interconnection process. To date, PG&E
7 has over 1,400 megawatts and 2,800 megawatts of active
8 storage under the CAISO GIDAP and PG&E WDT processes,
9 respectively. That's actually a number before our
10 cluster 9, which has just closed, so that number has
11 increased.

12 PG&E has progressed stand-alone and
13 renewable-paired storage generators through the current
14 interconnection study process. Under the direction of
15 the California ISO, PG&E has also successfully studied
16 the addition of energy storage to existing generation
17 through an accelerated material modification process.

18 CAISO-driven collaboration across PPO's and
19 storage stakeholders was fundamental in enhancing the
20 interconnection process to evaluate the impacts of both
21 the generation and negative generation aspects of the
22 energy storage generators. PG&E agrees that the
23 California ISO interconnection process is sufficient and
24 safely and reliably interconnect to energy storage
25 through PG&E interconnection systems. However, PG&E

1 believes additional work is needed to establish a
2 process in evaluating the aggregated distribution level
3 storage participating in CAISO's market.

4 PG&E is concerned that existing distributing
5 interconnection processes may not fully evaluate whether
6 any safety or reliability issues arise when a
7 significant number of DER's, Distributed Energy
8 Resources, responding in an aggregate manner to CAISO
9 market signals and dispatch instructions. PG&E believes
10 that the distribution of energy resource aggregator
11 should be required to complete an interconnection study
12 process before operating as an aggregation of
13 distributed resources in the CAISO market.

14 Thank you.

15 MR. McBRIDE: Good afternoon. Alan McBride
16 again with ISO New England.

17 I want to thank again the Commission for the
18 opportunity to speak today. My comments are focused on
19 the interconnection aspects of storage.

20 ISO New England is currently processing
21 interconnection requests for the addition of storage
22 devices in New England. These requests include the
23 additional storage to existing generation facilities and
24 the inclusion of storage devices among other types of
25 generation of new generation facilities.

1 While the ISO believes that the existing
2 interconnection procedures are adequate to manage these
3 interconnections will continue to moderate stakeholders
4 and take up discussions if it appears that enhancements
5 may be needed.

6 The ISO would also like to note that most
7 historic performance on the technology, the efficient
8 processing of these interconnection requests is
9 dependent on provision of a appropriately robust design.
10 The equipment needed to meet the established performance
11 requirements which our power factor ride-through and
12 frequency response and power system models need to
13 perform well and network study analysis. After the
14 interconnection process is complete, the ultimate aspect
15 of participation metering telemetry, et cetera, for a
16 storage facility, will depend on the markets in which
17 the resource has chosen to participate.

18 Thank you.

19 MR. RUTTY: Good afternoon. Steve Rutty
20 from California ISO. I'm the director of grid assets,
21 oversee the generation of interconnection process there.

22 And storage has become front and center at
23 the ISO over the last couple of years. We have held at
24 least four stakeholder efforts to discuss
25 interconnection efforts, market efforts, and operation,

1 both operational issues that go along with storage. Our
2 queue is heating up pretty heavily. We have currently
3 cluster 7 through 9, 77 projects with 8,700 megawatts of
4 storage that are trying to interconnect, 34 of these are
5 hybrid units, a couple that are flywheel.

6 So short opening statement. We're heavily
7 into it, we know we have -- I am trying to remember who
8 said it down there, we are early on the learning curve.
9 So I'm sure we'll be making changes as we go forward.
10 But currently, as Dave said with PG&E, our processes are
11 allowing a very competitive market from the storage
12 area.

13 MR. HERBERT: Great. Thanks a lot guys.

14 So the first topic we had teed up for
15 discussion is whether the existing small and large pro
16 forma interconnection agreements and procedures are
17 sufficient to accommodate the interconnection of
18 electric storage resources? So the question is, have
19 you had any difficulties using the existing pro forma
20 agreements or pro forma procedures for large or small
21 generators in your region for the transmission providers
22 or in any region for the developers when interconnecting
23 electric storage resources? And if so, can you please
24 explain those difficulties? And we're just go down the
25 line from my left.

1 MR. EGAN: So for large generation-sized
2 battery interconnections, no problems at all. Small
3 generation, they have a propensity to come in under our
4 very small gen, less than 10 kW inverter base and under
5 5 megawatt inverter base. The issues there, though,
6 pure distribution, the interconnection process is not
7 jurisdictional. So that's the only rub we have there.
8 But we typically coordinate with our transmission owners
9 to work through the state process and establish if
10 they're trying to participate in the PJM market, we get
11 them at wholesale market participation agreement so that
12 they're able to do that upon completion of the
13 interconnection process through the state's
14 interconnection process.

15 MR. EMNETT: Mason Emmett with NextEra.

16 So our four projects that we're operating
17 are within PJM, and I'd say PJM has been great and the
18 TO's we have interconnected with have been great. But
19 we're learning our way through the process. We've
20 co-located our projects, so issues that we found are --
21 as PJM has over time kind of maybe improved upon the way
22 or learned its way through the studying process, we see
23 slight differences in system impact study approaches
24 with respect to modeling, injection, as Dave said,
25 there's a modeling of withdrawal that makes sense to us

1 particularly in a weak area of the system, so those
2 studies make sense. But the modeling of thermal
3 violations associated with new injection, in some
4 instances we've been modeled as if the battery is just a
5 complete injection above the interconnection that the
6 customer had, even though we were proposing not to
7 increase that amount. In later system impact studies,
8 it appears that's not the case, but we're not entirely
9 sure.

10 So we'd like just to go forward not only in
11 PJM but in other RTO's, just more clarity, and this kind
12 of gets into the later issue in topic 3, but it's one
13 that's important to us.

14 The mechanics, in terms of the mechanics,
15 yes, there are kind of practical issues in working
16 through the interconnection application and the
17 agreement, there are some provisions that don't apply,
18 there are questions that -- don't aren't really
19 relevant, and there the most part we've been able to
20 work through that. There is a little bit of a risk from
21 the developer perspective of if you're not answering a
22 question correctly that can lead to consequences in the
23 interconnection process.

24 So we've worked with the PJM rep to say, "Is
25 this how you're going to interpret my question with

1 respect so a storage device" -- and they say to you "We
2 were all good" and we get it in an e-mail and we're
3 fine. So that hasn't been a significant issue for us.
4 It's really more, conceptually, what is the project
5 doing when it comes on line? How does PJM model it?
6 And then make sure that reliability is protected.

7 MR. FERNANDES: Thank you. John Fernandes
8 from RES Americas.

9 I would agree with Mason, the RTO ISO
10 transmission owners, distribution owners, they've been
11 very willing and very collaborative to work with us, the
12 developers when it comes to interconnecting storage
13 resources. There's been a lot of questions in both
14 directions, a lot of studies, but that's okay, I don't
15 think holistically there's anything wrong with the
16 current process.

17 I actually want to go back to something that
18 came up this morning. We have a generator
19 interconnection process for supply resources; and then
20 we have a transmission planning process for transmission
21 infrastructure. You hear it all the time now, "We're
22 developing storage and we're trying to stack services."
23 And that's actually the primary business model for RES
24 right now. We are building facilities to serve as the
25 infrastructure for incumbent utilities. Whether it's

1 with an RT0, ISO, or even with utilities, that challenge
2 of, "Well, these guys over here do the wires and these
3 guys over here do the supply," that does not lead to a
4 smooth process for interconnecting a storage plan that's
5 going to do both. And so I think there needs to be a
6 more direct way to combine those conversations so we're
7 not having it two times with similar folks.

8 MR. GABBARD: Dave Gabbard, PG&E again.

9 With energy storage being -- having such diversity in
10 technology, and like was said before being early on that
11 learning curve, there's definitely challenges; we've
12 encountered a handful today. As Steve mentioned, we
13 have worked collaboratively across stakeholders to work
14 kind of through some of those challenges, and we are
15 effectively progressing storage generation through our
16 interconnection process using the existing pro forma
17 contracts. I think we're going to continue to see
18 challenges, but the collaboration that exists in the
19 community, stakeholder community is going to allow us to
20 address those challenges as they arise.

21 MR. McBRIDE: Alan McBride from ISO New
22 England. I would agree that the existing small and
23 large pro forma procedures are adequate, but I think to
24 the learning curve I think, as I think we've heard just
25 now, that the storage development community is coming to

1 understand what is required by the LGIP and the SGIP.
2 We've heard examples of proposals coming forward, as
3 we've explained with there's a power factor requirement,
4 ride through requirements, there's a frequency response
5 requirements. And we found ourselves with models that
6 actually capture none of the above. And we talked about
7 modeling this morning. We've taken some pains and we've
8 had the recently approved interconnection improvements
9 to very clearly lay out what are the data requirements
10 coming in to the process for modeling. And we expect
11 that that will help communicate to folks that how to get
12 into projects is having models that can hit the ground
13 running, and that's a part of what's associated with the
14 performance standards.

15 MR. RUTTY: I'm not sure I could add any
16 more than what my fellow panelists had said. Like Dave
17 mentioned, we did meet with our stakeholders including a
18 lot of storage interests, to really review what our
19 interconnection process looked like, what our pro forma
20 documents were. And it was pretty much consensus that
21 our current process will accommodate storage. And,
22 again, we're going to continue to watch it, we're very
23 early, cluster 7 has just finished its phase-2 studies,
24 we'll be moving to the LGIA phase very shortly. So stay
25 tuned.

1 MR. HERBERT: Great. Thanks guys.

2 Encouragingly, there's a pretty high level
3 of satisfaction it sounds like. I'll ask the next
4 question anyway's, so it might be a quick one. But do
5 you have any sort of suggestions for best practices,
6 potential improvements to the pro forma interconnection
7 agreements and procedures and how to accommodate
8 storage? I know Mason, you said with PJM there are some
9 non-applicable provisions provided they meet a data
10 requirement for example.

11 Has there been anything that's caused enough
12 heartburn do you think justify improvements.

13 MR. EGAN: Mason brought up a good point.
14 So when you have an ISA and you have, let's say, 100
15 megawatts of wind and you haven't built it all up, you
16 have 80 megawatts built you have 20 megawatts left that
17 you want to build up, the problem with the
18 interconnection service agreement, the way you would
19 make a change is through -- in ours is appendix 2,
20 section 3, which is material change to the project.
21 While it's still inverter-based, we do do a
22 vulnerability study on the wind. So the way we're
23 looking at it is if you haven't built out the full
24 hundred you, would need to come back to the queue for
25 the this performance since we haven't completed the

1 study. If it's not transparent when you use what we
2 call the "necessary study" -- I think that's what's it's
3 actually referred to in lower case -- PJM will perform a
4 necessary study, it's not public, it's not very
5 transparent until after you would correct the ISA. So I
6 probably should have mentioned that the first time when
7 we were talking about are there issues with agreements,
8 that is one issue of the ISA right now, try to change
9 technology that doesn't really allow for that. I think
10 the way we're handling it is appropriate, because we do
11 get the appropriate study in place to ensure it's
12 adequate.

13 And as far as -- he also mentioned the
14 increase, that comes to -- as Mr. Fernandes said, the
15 technology in how you're putting the output out on the
16 system, you need to be clear on what your output could
17 be to the system, worst-case. So while the machine can
18 be set to zero, they can also be set to some higher
19 value in the inverter capability. So as the
20 transmission provider, I have to make sure reliability
21 of the system is the worse case. Unless we're blocking
22 the box that allows that control so that you can't
23 deviate from that, we would have to study the worse
24 case.

25 MR. EMNETT: Mason for NextEra.

1 "Satisfaction" is a strong word in the interconnection
2 process.

3 (Laughter.)

4 One of our projects, a 10-megawatt project
5 involving partial use to sustained rights took two
6 years. So I can't say we're satisfied with that, but we
7 get it. We get that people are working hard on issues
8 and some of them are contractual and some of them are
9 study-related, and we wish they didn't happen.

10 In terms of kind of things to improve, yes,
11 that ability to take full advantage of effectively what
12 we've already contracted for, and so the studies that
13 PJM would need to perform, part of that I believe would
14 also load deliverability and the remaining studies
15 relate to the type of injection rights we're seeking,
16 whether it's energy-only or capacity. And so more --
17 it's not entirely apparent how going in we could define
18 what it is we as interconnection customer are seeking as
19 effectively a programmable device the conditions which
20 we are willing to accept in order to avoid any problems
21 on the PJM system. That type of -- so NextEra also, our
22 major subsidiary is Florida Power and Light, a
23 vertically integrated utility integrated utility, as we
24 are thinking about integrating batteries on that system,
25 that's the internal conversation we can have. This is

1 what that device can do; how can we operate it; how
2 might we want to optimize it. Well, that type of
3 conversation doesn't fit within the PJM process because
4 that's not the way the interconnection process is
5 designed, which is fine. We'll accept that process as
6 it is. But let's figure out a way to effectively, from
7 our perspective, maximize the assets that are already in
8 the ground because most of the batteries that we're
9 developing at this point are in the 30-megawatt range.
10 There are developers that are looking at much bigger,
11 but we're just looking at little incremental additions
12 to the system, and it seems like that could be easier.

13 MR. FERNANDES: So I think we've touched
14 upon a real key challenge, not only do we know how to
15 improve upon this. Entities that are responsible for
16 reliability have to plan for worst case scenario; that's
17 what's they've been charged with, I'm an ex-utility guy,
18 I completely get it. At the same time developers, we're
19 interconnecting a distribution to provide services to
20 the balancing authority. When the distribution utility
21 looked at the full charge discharge cycle of the
22 capabilities of the storage plan, it resulted in voltage
23 flicker-down on their system, and we were handed a \$2
24 million bill for system upgrades. We were able to show
25 them, we wrote a control algorithm, and we were able to

1 show them that you could slow down the responsiveness of
2 the battery to still provide the service that the
3 balancing authority needed but to completely mitigate
4 the voltage flicker farther down on distribution. And
5 the distribution utility accepted it and didn't require
6 one bit of upgrades. And so that's -- I certainly don't
7 think that the distribution utility's falling short of
8 their reliability obligations. They recognized and
9 accepted the fact that this is a controllable resource,
10 that a mathematical algorithm would prevent that plan
11 from doing something where, technically incapable on
12 paper, it was capable of going to the full charge and
13 full discharge instantaneously, but we prevented that
14 from happening. And I don't exactly know how to bridge
15 that gap between those responsible for reliability and
16 those of us that are designing these systems.

17 MR. GABBARD: Just quickly that I think both
18 sides of that spectrum have been touched on, I think we
19 really need to highlight that it's a balance. The
20 biggest benefit of energy storage is also one of the
21 biggest challenges is disruptibility and opportunities
22 to leverage. That flexibility to maintain the safety
23 and reliability of the grid, we have found opportunities
24 to leverage control systems and other control mechanisms
25 to maintain that safety and allow interconnection under

1 material modification process, for example. But we've
2 also had instances where developers want the flexibility
3 to be able to stack those revenue streams and be able to
4 perform in whatever potential future market that could
5 exist at some point and so we need to make sure that we
6 balance both sides of that spectrum and maintain that
7 safety reliability that we require on our grid.

8 MR. McBRIDE: The use of existing
9 interconnection capability and this may be something
10 that the Commission would think more about, maybe take
11 an example of, say, an existing hundred-megawatts
12 generator and a new proposed hundred-megawatt storage
13 facility. If the proposal would be to reduce that
14 existing from 100 to 80 and then replace the top 20 with
15 the storage device, that is certainly something that
16 could be studied. It would avoid the thermal analysis,
17 but we still would need to study the performance,
18 voltage performance and things like that, to ensure
19 there was no degradation. That's the study side.

20 I think there's also the interconnection
21 service and interconnection rights question, what has
22 actually occurred? Is it essentially a retirement of
23 rights from that first unit from 100 down to 80, call it
24 a permanent right? And for us in New England, that
25 brings up capacity market questions and the capacity

1 piece probably has to go through the capacity market and
2 dealt with in some way. It could be dealt with maybe as
3 a re-powering, so it's a partial re-powering of the
4 facility where it was presented and operated before and
5 in a different way afterwards.

6 So I think there are different options and
7 we may already have all the tools for that particular
8 proposal that we need, but it may be worth thinking
9 through the interconnection rights piece of it to make
10 sure what's actually achieved at the end of an endeavor
11 like that.

12 MR. RUTTY: Again, going last, I don't know
13 if I have a lot to add to what my fellow colleagues have
14 said.

15 (Laughter.)

16 It's just the process needs to be very
17 flexible. Developers make changes all the time. They
18 may come in with a solar plant and then halfway through
19 may want to take away part of the solar and add some
20 battery storage. The battery is a little bit different
21 than solar, so there's level of deliverability, that
22 level might go down. But it's something we would work
23 with them on. We allow all kinds of changes and
24 modifications through the process, as long as it doesn't
25 negatively impact the other interconnection customers

1 that are there.

2 So that's the key that we look at, we make
3 sure when someone comes in with a change that it doesn't
4 negatively impact projects to put them in jeopardy. But
5 there are a lot of opportunities to learn and meet with
6 these developers want to put in. So it's a very
7 creative market right now. It's a learning curve, lots
8 to look forward to.

9 MR. HERBERT: Great. Thanks again.

10 We've largely segued to the next topic
11 already, that is the modeling of electric storage
12 resources. John, you gave a nice example. Alan, you
13 talked about how ISO New England does it. Maybe you can
14 move through those a little bit quicker. But for
15 developers and potentially PG&E, you have any, I guess,
16 additional experiences with the way your storage device
17 has been modeled, either sort of unnecessarily delayed
18 the interconnection process or did not accurately
19 account for the resource operational characteristics?

20 And if so, would you recommend any
21 improvements or best practices to have that done? That
22 one's geared at the developers.

23 We have a follow-up question for
24 transmission providers.

25 MR. FERNANDES: So John Fernandes from RES.

1 I think one of the real challenges when it comes to the
2 modeling of storage is the only way -- that's been shown
3 to me, anyway -- for system operators is to model the
4 charging of a storage resource that's been treated as a
5 load. The charging of a storage resource is anything
6 but load mostly from a control perspective. So I think
7 -- and maybe that's where we the developers can come
8 together with the system operator and start to share
9 some modeling processes, how exactly do you show the
10 controllability of the charging of a storage asset, but
11 also keeping in mind that frequently when we are
12 charging a storage plant, we are doing so under the
13 instruction of the system operator because that's part
14 of the service we're providing. And that is rarely
15 reflected in a load construct really unless you're
16 talking about load curtailment, some type of demand
17 response-type idea.

18 MR. EMNETT: Mason Emnett from NextEra.

19 Not much to add, but there was a link
20 obviously in the conversation earlier today about when
21 wind and solar is modeled, capacity factors. It matters
22 in the RTO's analysis what the assumptions are in the
23 operation of the resource. And as John and Dave
24 acknowledged earlier, the way that PJM would study is
25 maximum charge at the worse time and maximum output at

1 the worse time. And that's not the way the asset is
2 going to operate, we all know that. So then how do we
3 get to a place where you would have some reasonable
4 function or control around the way that the asset's
5 going to operate.

6 MR. HERBERT: Dave, do you have anything on
7 modeling? I know you're kind of the middleman between
8 the developers and the operators.

9 What's PG&E's perspective?

10 MR. GABBARD: I don't have anything to add
11 from an engineering standpoint. But I do want to add to
12 what John referenced about the differences between the
13 charging of an energy storage device and load. If you
14 noticed in my opening comments, I deliberately called
15 out negative generation. I think that's been one of the
16 biggest successes in the California ISO process, to
17 really look at how do we model and how do we
18 interconnect energy storage. The fact that energy is
19 intended to operate in a way that helps the grid is
20 something that we need to take into consideration. And
21 understanding how we can leverage the existing generator
22 processes to evaluate the gen and negative gen is
23 important, and it helps clarify some jurisdictional
24 issues that also come up around energy storage and
25 allows us to effectively use these as they stand.

1 MR. HERBERT: Great. Thanks.

2 So all of questions for the transmission
3 providers, Dave kind of described us for California
4 already, but you briefly described a methodology for
5 modeling electric storage resources during the
6 interconnection process. And specifically with respect
7 to how it is modeled as generation, load, or both, and
8 whether it does accurately account for the generally
9 fast and controllable nature of these type of resources?

10 Dave, if you want to start?

11 MR. EGAN: That's a tough question, because
12 it depends on how they're using the device. That's the
13 rub. I think, as we learned, it requires communication
14 with the customer and how they're anticipating using the
15 device so we model it properly. I don't know if that
16 covers the question. It's very difficult to have a
17 one-size-fits-all for them to operate on the system.

18 MR. HERBERT: Okay, got it.

19 MR. MCBRIDE: So in New England when it's
20 generating, we pretty much model it essentially the same
21 as any generation base on the technology. We'll be
22 doing the appropriate reviews that we would do for
23 similar type of technology, especially for
24 inverter-based injections. The study as a load is an
25 interesting one, at least on the transmission system in

1 New England. We have had storage in New England for a
2 long time, and other reasons -- we have pumped storage.
3 We have been trying the market mechanisms further up the
4 road. So we have, for example, an asset-related demand,
5 which is not load but it's the ability to buy from the
6 transmission system and the pumped storage devices use
7 that today when they're pumping, and then they pay the
8 locational marginal price, et cetera.

9 So when we're studying a storage device
10 we'll be doing with that in mind, so we're not going to
11 be studying it as firm load or as network load. So a
12 new network load, let's say 20 megawatts, would be
13 studied under a set of conditions, it would probably be
14 more conservative than the asset-related demand,
15 storage-type load. But that network load is going to be
16 aimed at transmission service, it's going to be paying
17 for the storage transmission service. So in turn, it
18 has a higher level of transmission service.

19 So the storage device, when it's acting as
20 the load, we will have ensured there's no adverse
21 impacts when it's essentially opportunistically taking
22 power off the system to charge, and there could be
23 upgrades to make sure there's no adverse impact. But
24 other than that, it is a different concept from network
25 load so we're studying it in accordance with the service

1 it's going to have going forward.

2 MR. RUTTY: Very similar to ISO New England.

3 We look at the charging aspect, as Dave mentioned, the
4 negative generation, and the reliability studies we look
5 at it to make sure it doesn't cause any issues and that
6 our congestion management or the market signals can make
7 it work. We don't identify upgrades based on charging
8 as long as the unit is dispatchable, is responding to
9 market signals, and is curtailable if that's needed.
10 Similar to them, when it's acting as a generator it's
11 studied just like any other generator we have in our
12 queue.

13 MR. GABBARD: Real quick, one point on that
14 just to clarify. When we are studying the negative
15 generation or charging characteristics of the storage,
16 we will look for upgrades required in order to
17 accommodate firm load and we will communicate those if
18 identified in the study report, but they're there for
19 informational purposes only. So we will not move
20 forward with build out of an infrastructure for a firm
21 road because we understand that the market signals are
22 intended to account for that, any potential congestion.

23 MR. LUONG: I guess just I had a follow-up
24 question. John mentioned earlier that storage is
25 somewhere between generation interconnection and

1 transmission process, are you trying to say that one of
2 the ways to connect it is the power piece of equipment,
3 that you should look at storage and the transmission
4 piece?

5 MR. FERNANDES: So we are definitely
6 developing storage. Probably right now it's more
7 distribution, I think most of your incumbent utilities
8 are trying to take small bites of this. So we're
9 looking for more infrastructure-upgrade referral-type
10 process, but we are also looking at storage as
11 transmission as non-transmission alternatives possibly
12 to be submitted into ISO planning processes. I don't
13 know that the challenge that I brought up earlier
14 specifically related to the little piece of
15 interconnection. But I think there's something, and
16 maybe this is for the separate market participation
17 docket, I don't want to get too out of scope for today,
18 but there is an issue when we are developing storage
19 plans that are being built to offer multiple services.
20 And one half of these services is something related to
21 infrastructure, whether it's congestion mitigation,
22 reliability, voltage control, power quality, whatever it
23 may be, and then perhaps we're collecting supplemental
24 revenues from ancillary services from an energy
25 market. Those are not the same groups of people that

1 we're talking to when we're trying to plan the
2 interconnection and operation of that facility and when
3 we're trying to -- on the infrastructure side, typically
4 that's going into infrastructure rates and on the supply
5 side that's going into the market to collect revenues.
6 And there are different groups of people, they're
7 different timelines, they're different studies
8 altogether. And that is holding up the process a little
9 bit.

10 So I don't know if I answered your question.

11 Okay.

12 MR. RUTTY: Steve from the ISO.

13 That's the exact question we've been trying
14 to ask, "Well, can it be a transmission asset?" And the
15 ISO has to be very cautious that it doesn't get into
16 operating an asset where it can actually change the
17 market. And so if we did put it in as a transmission
18 asset, it would have a very limited use and pretty much
19 limit what the storage system could do for us if it was
20 a market participant. So there's that conflict we've
21 been dealing with.

22 MR. FERNANDES: And that's an excellent
23 point and it's absolutely correct. And I would not go
24 out to the market, broadly speaking, and develop a
25 storage plant that has an operational obligation to the

1 system operator. I'm not going to put a storage plant
2 in rates in transmission or distribution and then go to,
3 say, a capacity market and try to clear that option and
4 take on a capacity obligation at the same time. There's
5 going to be a primary driver for any storage plant that
6 has stacked services, and that primary driver is always
7 top of the list. And it might not necessarily be what
8 that storage plan is dispatched for the most hours per
9 year, but it always get the priority. So when we write
10 our algorithms, that's what's at the top of the stack.
11 Meeting that utility obligation or on the other hand a
12 capacity obligation, there are markets that offer
13 tremendous flexibility day-ahead and real-time, even
14 inter-hourly, to come in out of that market and just
15 begin to collect supplemental revenues, these are not
16 the economics that are driving the overall cost recovery
17 system but they're certainly contributing.

18 MR. HERBERT: All right. Let's move on to
19 the next topic.

20 Next one was the interconnection of combined
21 storage and generation facilities. We had a number of
22 kind of subtopics identified here, interconnection
23 service, combined facilities, operational understanding,
24 telemetry and metering for those facilities, and the
25 appropriate process for adding storage to existing

1 facilities. So we'll start at the top of that list.
2 We've heard sort of mixed opinions, I guess is one way
3 to say it, regarding the appropriate level of
4 interconnection service for these types of facilities,
5 whether it should be sort of the cumulative rate of
6 capacity of all of the assets behind the point of
7 interconnection or whether it could be somewhat limited
8 level of interconnection service based on how the
9 developer actually intends to operate the device.

10 So we'd just like to, I guess, hear from all
11 of the perspectives at the table, what you view as sort
12 of the appropriate level of the facilities to be.

13 MR. EGAN: Dave Egan, PJM.

14 So the general history of where we've seen
15 these, typically some form of renewable with the battery
16 storage, and the issue there that drives up cost is
17 having the meter separately. So in order to get the
18 renewable energy credits, the renewable resource has to
19 be entered separately. That's really the biggest issue
20 I see. As far as everything else, it's pretty
21 straightforward as far as that studies.

22 MR. EMNETT: Mason Emmett for NextEra.

23 I think we would agree in terms of
24 straightforward as to the studies, we understand how the
25 studies is being performed and what is being done. Our

1 ask would be what is being studied actually reflects the
2 injection that we are requesting. And so as an owner of
3 large asynchronous resources within the system, which
4 are highly controllable and we're attaching a battery
5 that is highly controllable, it's not immediately
6 apparent to us why we could not attach a battery to an
7 existing asset, say a wind asset, that if we've got
8 excess interconnection rights that we are not using,
9 then transfer those over. Could be transferred over
10 depending on our financing legal structure, you might
11 transfer over within the existing entity, but that's
12 kind of in the weeds. But there should be an
13 optimization.

14 And then it also seems to us that you
15 shouldn't necessarily be limited in terms of installed
16 capacity to your interconnection rights with
17 controllable devices. You should be able to include
18 more on the customer side of the control down and never
19 exceed the injection rights that you have already agreed
20 to that, that's already been studied. Now, there
21 wouldn't need to be studies of withdrawals, there
22 wouldn't need to be stability studies. But the thermal
23 studies of the injections it would seem have mostly been
24 done. And if we can kind of find agreement on that,
25 then one of the more complicated issues in the

1 interconnection process, as you've heard all day long,
2 is the linking of interconnection requests through the
3 study process and the queues, and the dropouts causes
4 the delay. If you could take one element of that and
5 put it aside for these type of projects, because they're
6 going to control in on them. And that generally has not
7 been something that has been well-received from the RTO
8 perspective. So if we could find comfort around that.

9 There are a couple of examples we could
10 point to where the RTO's have accepted interconnection
11 agreements for install capacity and in excess of the
12 injection rates and the maximum facility output. And
13 there is contractual language in the ISA saying "I
14 understand I will never exceed this number, I have more
15 installed but I will never exceed this number." And we
16 understand that, we can handle that. And that would be
17 our ask.

18 MR. QUINN: I guess this question is really
19 if you had a red button that you're not controlling, we
20 have a red button that says "if you exceed, we'll
21 control," and then would you be comfortable with them
22 having a red button?

23 (Laughter.)

24 MR. EGAN: I would say what we want is they
25 would install a power flow relay that would limit the

1 output, the problem you have is if you have the
2 capability and you can exceed the thermal capabilities
3 we have studied you could cause damage. I would prefer
4 to see, if you're going to say I've got 100 megawatts
5 wind farm and I'm putting my 20-megawatt battery there
6 but I'm going to limit it to 100, then put something
7 there to ensure that the system is never in jeopardy.

8 MR. EMNETT: And we would be fine with
9 accepting the limitations. I think the red button is
10 there, it's in the control room at PJM. We can be
11 curtailed and the operators can -- they monitor us, they
12 understand what our output is and they would call us if
13 we were exceeding. Now, would it actually be reasonable
14 for the operators to note for every resource the amount
15 that they are and are going to track it? MISO has
16 cracked the nut with net zero interconnection service,
17 there are reporting obligations on behalf of a customer
18 who has installed more capacity on its side of the
19 interconnection than it actually has interconnection
20 rights to. Pro forma agreements which govern the
21 relationship between the two entities, if they're
22 separate entities on the EOI side, as well as the
23 relationship between the monitoring, the TO, and MISO.
24 And so it's all doable, it's just are we going to do it?

25 MR. QUINN: Do you have a comment?

1 MR. McBRIDE: Yeah. I was just thinking to
2 myself I think all the ISOs, would want the red button
3 regardless, and that should be in place. I think
4 everything that Mason talked about is doable and I guess
5 I feel like a little bit I might have jumped ahead in my
6 earlier response to this topic. The key would be very
7 concerned about a situation where facilities
8 interconnected that is physically capable of injecting
9 more than the rights that are associated with it. So
10 there will need to be appropriate protections and
11 assurances for dealing with that.

12 But along with that, I think just to
13 reiterate the earlier comments, just to make sure the
14 resulting service and upgrading rights and descriptions
15 are very clear and implementable on all sides.

16 MR. FERNANDES: I guess maybe I had my own
17 follow-up question. So for the system operators, I
18 understand the assurances you got as far as we'll give
19 you the red button to put into your control room. As
20 far as again going back to the control platforms that
21 sit, just loosely speaking here, they sit between the
22 actual storage plant and then the SCADA system, is that
23 something different than the red button? Is it the same
24 level of assurance as the red button what I've shown you
25 a control algorithm that technically prevents that

1 whatever is behind that point of interconnection from
2 injecting beyond X or withdrawing?

3 MR. EGAN: My comment is that would be
4 you'll have to show me that failsafe. In other words,
5 it can't be overridden by you, since you're in control
6 of it, you're injecting on my system. That's why where
7 said if you could padlock it and it could never break, I
8 think I could trust it, otherwise, I think I'd want
9 something.

10 (Laughter.)

11 MR. HERBERT: Anyone else?

12 Dave or Steve. Either.

13 MR. RUTTY: I agree with them. I agree with
14 what's been said. California ISO does require that the
15 flow is limited to that maximum amount, whether it's by
16 protection scheme or a device, or other, as proven to be
17 failsafe we're not going to put the grid at risk.

18 MR. HERBERT: We'll jump to the next
19 question. This one is for the RTO's and maybe PG&E as
20 well.

21 What are your primary operational concerns
22 of these combined storage and generation facilities?

23 Dave, I know you mentioned earlier modeling
24 discussion, you don't necessarily know how to model
25 them, or maybe you do.

1 MR. EGAN: I think we know how to model
2 them. It's just if you're going to set it at zero and
3 never inject a lot of energy, I think that's what you're
4 getting at with that. The problem is if he's
5 controlling that, it could inject a lot of energy, so
6 it's really a function of what you're installing, and I
7 would want to make sure my system could handle --
8 suppose somebody one day went in and messed up the
9 controls and put power out. I need the study so my
10 system is not damaged, that's really the issue. How do
11 we get past that? I think it's just a communication,
12 talking to each other, so this is all new stuff, so.

13 MR. McBRIDE: If your question was in terms
14 of modeling the proposal and identifying scoping out the
15 study? I think we can do that.

16 Was that what you were asking.

17 MR. HERBERT: Just generally whether you
18 have kind of operational concerns with these combined
19 facilities.

20 MR. McBRIDE: I would say, other than the
21 stuff we've talked about, I think we can study a
22 proposal and we can identify the appropriate
23 interconnection. You asked about very quick ramping,
24 for example, if that was something that needed to be
25 studied, and we have not yet -- to this point identified

1 a system impact study issue that would be associated
2 with that, it's just an attribute of the system that
3 will be there when it's operating. So we don't have a
4 concern for that particular aspect, for example from a
5 system impact study perspective.

6 MR. RUTTY: Yeah. On the same line, we're
7 very pro having this type of facility come in. And it
8 really helps us with the operation, especially getting
9 on the ramps for the peaks and extending the life/the
10 output of a solar plant or a wind plant, being able to
11 take over when the clouds come over, I mean, it's
12 definitely a very huge benefit to us, so we're looking
13 for any way to accommodate and bring these type of
14 facilities on line.

15 MR. GABBARD: I just want to emphasize that
16 as a PTO, we have an interesting position where we're
17 balancing multiple assets on the grid, both safety and
18 reliability and affordability for our customers. And so
19 most of you were here earlier today and we clarified
20 that in the California ISO service territory network
21 upgrades that are triggered by generation are ultimately
22 funded by ratepaying customers. So we are always
23 looking for opportunities to minimize that financial
24 impact on our customers, we always look for these
25 opportunities to avoid overbuild of our system. But at

1 the same time, we want to make sure whatever assurances
2 we're relying on are sufficient to maintain that safety
3 and reliability. So not only do we have that balance
4 and make sure we are good on both fronts, that's just
5 the predicament that we're in.

6 MR. HERBERT: Okay, let's go ahead and jump
7 to the next topic. The next one was the potential
8 processes to facilitate the interconnection of electric
9 storage resources. I don't think it's any secret that
10 every developer would like to have their asset on the
11 grid as quickly as possible. The Commission has in the
12 past sort of acknowledged differences in technologies.
13 We have a fast-track process for small generators.

14 We have a 10-kilowatt inverter process for
15 small generators, there are the network provisions that
16 you mentioned, Mason.

17 We have provisional agreements. A lot of
18 these were developed both out of, I guess, acknowledging
19 the technology differences and also sort of the need to
20 bring these resources on line faster. So I guess how
21 could -- if we were to decide that that need did exist,
22 how could the Commission justify sort of facilitating
23 the interconnection of electric storage resources? And
24 also, if we did, what would be the best means to bring
25 those resources on line faster? We can go ahead.

1 MR. EGAN: I'll start with the last part of
2 that, because the first part I am not sure I can even
3 answer. The last part about moving faster, we have an
4 issue, I brought it up in the second conference
5 discussion earlier today. At PJM, the small gen several
6 years back requested that anything under \$5 million be
7 allocated within the group. So the problem with that is
8 it actually clustered together everybody in the queue.
9 We have to wait for a queue so we can determine who
10 would get cost allocation if it gets pushed -- if a
11 facility gets pushed over a hundred percent, they will
12 all share in it. So we can't move anybody fast. And
13 that's a tradeoff between seed and cost share. So, to
14 me, that's the biggest issue right now in our footprint
15 would be the under \$5 million cost allocation rule. And
16 coupled with that is our alternative queue study process
17 that says if anybody is sharing in a facility overload,
18 we have to wait for the queue to close. So both of
19 those provisions that were added, I think were around
20 three to five years ago in our tariff, are obstacles,
21 very fast in interconnection small generation.

22 Did you want to clarify your first part of
23 that better.

24 MR. HERBERT: I guess it's just, if there
25 was an inclination to do this, I mean, we've heard that

1 these are, for example, fast controllable devices,
2 operational requirements in the grid are changing.

3 From an operator's perspective, could PJM
4 sort of philosophically justify bringing these resources
5 on line quicker or operationally? What would the
6 requirement be?

7 MR. EGAN: I'll pass on that. That will be
8 in our comments.

9 (Laughter.)

10 MR. EMNETT: Mason Emmett for NextEra
11 Energy.

12 Not having to operate, at least that system,
13 that's kind of where we would come from the developer of
14 storage within a RTO market, is within a region that is
15 big and complicated and involving lots of effectively
16 interconnecting resources. Moving through the
17 interconnection process because of the way the studies
18 were performed, a way to distinguish between relatively
19 small -- you could do size requirements, you could do
20 stability requirements, a shifting of risk between
21 interconnection customer and coming along the battery
22 developer, and saying, "I will move more quickly through
23 the process but I will do that at my risk. If I sign an
24 interim ISA now and go ahead and get faster service,
25 then I'm subject to the outcome of whatever the studies

1 may be at a later point in time. And I understand that
2 and I accept that that's a possibility." I think you
3 would justify that with essentially that sharing of risk
4 and being able to control around whatever the issues or
5 constraints might be in the interim or the concerns,
6 that would have to be managed the parallel study process
7 that would have to be managed within the RTO, and that
8 wouldn't be easy I imagine. But if it would be a way to
9 pull some resources out of the queue, and might have
10 other benefits just in terms of trying to clear out some
11 of the term that occurs.

12 Because another point that was made earlier
13 in the day in changing technology -- and I think
14 somebody referenced it on this panel -- storage
15 developers have that same issue. By the time you get
16 through two-year process, the technology has changed, it
17 just has. So what you thought you could order a couple
18 years ago, you can't order anymore. So you got to go
19 through the process of just making changes. Is that
20 material or not? Is that going to go? It's a lot of
21 the things you find applied to a different technology.

22 MR. FERNANDES: That last point was a real
23 good one. John Fernandes from RES.

24 Unfortunately, haven't done enough of these
25 within one market or with one transmission owner where I

1 can point to a spot within the interconnection process,
2 a contractual agreement, the modeling, our control
3 algorithms. But I think hopefully we can start to
4 identify somewhere in those operating parameters where
5 we show this is not every system at max gen and
6 especially max load at the worse possible times. I
7 think that should be able to advance a storage
8 interconnection farther down the road maybe through a
9 faster-track process. I really think it's going to come
10 down to the operator's trust in the control algorithms
11 and what we as the developer, why are we building that
12 plant? What are the contractual obligations we have?

13 MR. GABBARD: So over the last 10 years,
14 we've done a lot of work in ways to look at the
15 acceleration process. We have a strategy and facility
16 process, we have the material modification process to
17 modify an existing generator. But I want to caution the
18 Commission. We are talking about large-scale
19 generators. We have a generator interconnection process
20 for a reason, to evaluate the impacts on the grid and
21 maintain safety and reliability. While we're going to
22 continue to partner with stakeholders to identify ways
23 we can tweak those existing fast-track processes and
24 other processes to accelerate interconnection, we want
25 to maintain that safety and reliability.

1 And I want to clarify a couple of things
2 that were called out earlier today. The folks
3 referenced the long study process or the long
4 interconnection process. My comrade earlier from
5 California ISO referenced the two-year study process
6 that we have in the state of California. But I want do
7 clarify that the actual studies being performed by the
8 PTO or the RTO are a matter of months. Through the
9 study process and through the interconnection process
10 are iterations of tasks that are on the PTO, RTO, and
11 tasks that are on the interconnection customer. A large
12 portion of timeline through the overall interconnection
13 process are periods of time when we're waiting when the
14 interconnection customer's working to get a PPA,
15 financing for their project, and other aspects. It's a
16 natural flow. And so understanding where there are
17 things that are not working, we definitely need to come
18 together as stakeholders and find ways to fix those.
19 But some of the timeline is actually more effective,
20 it's actually a more tortoise and hare situation where
21 it's effectively moving through the process at a pace
22 where we allow developers to effectively develop their
23 projects, and ultimately reach our goal which is getting
24 more generation on line whether renewable or otherwise.

25 MR. McBRIDE: To answer as the open access

1 transmission provider in New England, I don't have a
2 reason -- with respect to interconnection perspective or
3 reliability perspective, a reason why these proposals
4 would be treated differently than other proposed
5 requested to interconnect to the grid.

6 MR. RUTTY: In consideration of time, Dave
7 pretty much took every note that I had written down to
8 answer that question. The only thing I can say is the
9 material modification has proven very valuable to the
10 ISO where we've been able to add storage to existing
11 projects, ensuring that it didn't add a major impact to
12 the grid or to other customers.

13 So being flexible in that environment is
14 pretty important to us and how we accommodated a lot of
15 changes to existing or near-existing plants. And the
16 re-power process as well has allowed existing generation
17 among others to re-power with batteries and other types
18 of resources. So again, we have to look at it for
19 reliability, we have to make sure it's a reasonable
20 solution, so it's been fairly flexible for us.

21 MR. HERBERT: Commissioner LaFleur, do you
22 have a question?

23 COMMISSIONER LaFLEUR: I wanted to ask a
24 little bit of a philosophical question. I mean, when I
25 used to run a distribution company, I would ask people

1 if you lost the whole system and you had to start from
2 scratch, what would you put up? Because I know it would
3 look nothing like what's out there. Because if you
4 don't know what an ideal is, you can't even make
5 incremental progress. So the situation right now is,
6 just the reality, is storage is a product in limited
7 quantities that being -- we're trying effectively to
8 graft on to a system that was built for transmission,
9 distribution and generation. So in the time that we had
10 the critical mass of storage and you were building a
11 storage-centric to compensate it or whatever, would
12 there be a parallel set of a grievance to what we have
13 now, I mean, what would the future look like, if anyone
14 has any thoughts, when storage is really big? Would it
15 be like generation and we would be like a another sort
16 flavor of generation that we would just pay that way, or
17 is there some way of thinking about this that we're even
18 missing in the way we think about paying it? Because I
19 think every time we think of storage we're trying to fit
20 it in another peg. Everyone doesn't have to answer, but
21 we have all these experts here, if anyone has any
22 insights I would welcome it. Because my mind doesn't go
23 to where that is, it just goes to where we are now.

24 (Laughter.)

25 MR. EMNETT: Mason Emnett from NextEra.

1 It's a timely question. Yesterday, about
2 100 people from our company were together and we spent
3 six hours together on storage, as a
4 where-have-we-been-and-where-are-we going conversation.
5 And that's not an easy question to answer. There really
6 is no kind of current answer other than the way we've
7 thought about it is. As an organization that has a
8 large vertically integrated utility and an emergent side
9 of this outside of Florida, we answer the question
10 differently depending on which side of the house you're
11 on. Right? And it is much easier, frankly, for the FPL
12 side of the house to step back and think about how would
13 I integrate this resource that does multiple things for
14 me? And I have a rate base. I have a transmission rate
15 base and I have a generation rate base. Allocation
16 between those with respect to cost recovery, which then
17 takes me into what's the function and what the benefits
18 I'm getting out of it and can I demonstrate the value of
19 that investment. Getting more value than I am for the
20 investment itself for purposes of rate recovery.

21 When you move into the organized markets,
22 it's extremely difficult to think about how you stack
23 those functions and values in a market structure that is
24 designed for generation. And it's designed for a
25 generation in a way that makes sense with the physics

1 and the operation of the system, but then a resource
2 that steps across all those boundaries is tough. And I
3 think that's the question that, frankly, we all need to
4 answer and we'll need to answer it probably in the next
5 three to five years.

6 COMMISSIONER LaFLEUR: Because we're making
7 decisions now that are putting us in a path to where we
8 might be when storage is bigger.

9 Do you know what I mean?

10 MR. EMNETT: And that is the way that we are
11 thinking as to storage. Right now we're operating
12 projects provide frequency regulation. And that is
13 nothing of what these resources can do, but it is the
14 product that is compensated and it justifies the
15 investment. And we're learning, we're learning from the
16 operation of those assets from going through the
17 interconnection process and figuring out ways to manage
18 it. And then we're looking forward to, what are the
19 additional things we can do? We haven't gotten there
20 yet, but hopefully we will and then we'll start to stack
21 the things out and hopefully get there.

22 MR. FERNANDES: So I'll use Mason's analogy
23 of what we're doing on the corporate side. Our wind
24 guys don't do storage. Our solar guys don't do storage,
25 our transmission guys don't do storage. Our storage

1 guys do storage. We have a dedicated global storage
2 team. And when I said I was taking Mason's idea, I
3 believe he brought it up in a conversation that a
4 storage contingency came here to the Commission years
5 ago when demand response first started taking off. We
6 tried to put it into these existing constructs and that
7 was an absolutely horrible fit. And this Commission
8 finally said: "Create rules for the demand response."
9 And I am not trying to add to the tariff books, someone
10 is going to stab me with their pen, I know.

11 (Laughter.)

12 It adds more paperwork, more operational
13 complexity, more market products and everything else.
14 But storage is very much its own asset class that
15 touches just about every other asset class that hits the
16 grid. So I think that really begs the justification for
17 let's stop talking about storage as generation, as a
18 negative gen, I get it but those are still dangerous
19 semantics. Storage to storage, and I think it would be
20 really want to be able to accommodate storage at a large
21 scale five or ten years from now, those rules need to
22 start going into place now.

23 MR. McBRIDE: I was just going to quickly
24 offer because my own boss talks about it this way a lot.
25 We have had storage in New England markets since the

1 beginning.

2 COMMISSIONER LaFLEUR: Pump storage.

3 MR. McBRIDE: We have pump storage. And
4 it's almost 2,000 megawatts, which is relatively large
5 for our system. What I understand is that that storage
6 was originally installed to capture essentially what we
7 now call "energy price arbitrage" where it would pump
8 during the night when prices were low and generate
9 during the day when prices were high. And it still can
10 do that, but now instead, for the most part, it
11 participates more in reserves and regulation markets.
12 So that evolved by itself, and there's been some
13 adjustments in our markets to deal with that. So it
14 could be that the technology will come forward and the
15 technology will tell us how it wants to competitively
16 participate.

17 COMMISSIONER LaFLEUR: Well, thank you.
18 I'll let you get back to interconnection. It just seems
19 like we keep going around this loop.

20 Thank you.

21 MR. HERBERT: If anyone else have anything?
22 I think in the interest of time and with respect to
23 everybody's weekend plans, maybe we'll just call it
24 right here. We're already a little bit over. So thank
25 you again for coming. I think this has been a very

1 interesting conversation. I think it's the beginning of
2 a very interesting conversation. We do have a couple of
3 closing remarks from Adam, so don't get up just yet.

4 But thanks again.

5 MR. PAN: I'll be brief. It's been a very
6 interesting and informative technical conference we've
7 had today. We thank everyone for attending. We thank
8 all of our panelists who came out and participated
9 today, especially for you who traveled from somewhere to
10 get here.

11 In terms of next steps, to better organize
12 issues that are being considered, Staff is looking to
13 put out a targeted request for comments sometime soon.
14 To the extent that includes questions, we ask that you
15 respond to the specific questions. And please continue
16 to monitor the docket and look out for that.

17 Thank you.

18 (Whereupon the technical conference is
19 concluded at 4:54 p.m.)

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CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding
before the FEDERAL ENERGY REGULATORY COMMISSION in the
Matter of:

Name of Proceeding:

REVIEW OF GENERATOR INTERCONNECTION AGREEMENTS
AND PROCEDURES
AMERICAN WIND ENERGY ASSOCIATION

Docket No.: RM16-12-000

Place: Washington, DC

Date: Friday, May 13, 2016

were held as herein appears, and that this is the
original transcript thereof for the file of the Federal
Energy Regulatory Commission, and is a full correct
transcription of the proceedings.

Official Reporter