BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

ELECTRIC SYSTEM INVESTIGATION TEAM :

RELIABILITY RECOMMENDATION CONSULTATION :

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The above-entitled matter came on for technical workshop, pursuant to notice, at 8:00 a.m.

APPEARANCES:

TOM RUSNOV, Canada

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DAVE HILT, NERC

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P R O C E E D I N G S

8:00 a.m.

MR. CAULEY: My name is Gerry Cauley. I work with NERC and I will be facilitating the meeting but most of the actual work will be done by other show will be speaking and presenting.

I'd like to start off first of all mentioning that this technical conference is sponsored by the U.S.-Canada task force on the August 14 blackout and representing that task force today is David Meyer of the Department of Energy and he' going to open the conference with a few remarks from the Task Force.

MR. MEYER: Good morning ladies and gentlemen. Welcome on behalf of the Task Force. As I am sure you have all had some opportunity to take at least a quick look at our interim report that we issued in November and while we're interested in your comments on the report, the primary purpose of this meeting is to obtain your ideas on recommendations going forward. That is, recommendations pertaining to policy or to institutional changes, organizational changes, operational changes that are needed, recommendations of all kinds pertaining to improving to reliability of the nation's electricity grids now and the North American electricity grids.

So at the meeting today is formatted to

facilitate discussion, that is, the panelists will frame issues and put questions on the table and then once those questions are on the table then we will open it to discussion and get your ideas.

But in the event that, well, it's frequent, given the complexity of these questions, I think it likely that there will be issues that can be still aired further fruitfully or maybe after you leave the room, leave this meeting, you will get additional ideas that you think are relevant.

So I want to encourage you to make full use of the websites that we have available, the mailboxes, the electronic mailboxes that have been set up. THere's one mentioned here in the agenda I see there is one for the United States and one for Canada where you can file comments and any of those comments will then be transferred to the DOE website and naturally we will see whether the Canadians have done similar things.

At any rate any comments that we receive will be put on DOE's website so that you can access that website and see the full record of commentary that has been provided and then you can offer additional comments or you can respond to other comments or whatever you would like.

But it is a great opportunity to get a very full discussion of these issues so I encourage you to make good use of that.

With that, Gerry, let me see -- we have Tom Rusnor here also.

MR. RUSNOR: Good morning ladies and gentlemen. I'd just like to inform you that we're planning a technical conference for Toronto on January 9. The intention is that will be complimentary to this conference and hopefully will not be duplicative and also to give enough opportunity for those who could not attend today to come and make their views known and to exchange ideas. So if you or your colleagues would like to attend we'd be pleased to welcome you. It will probably be held at the Westin Harbor Castle Hotel in Toronto and that would be January 9.

Following this session we will craft an agenda that as I said hopefully will compliment this session. Thank you.

MR. CAULEY: Alison Silverstein who is also one of the co-chairs of the electricity working group will be here later today. She had a conflict first thing this morning. She will have Alison and David and Tom as the three co-chairs of the electricity working group of the U.S. - Canada task force.

Supporting them in the investigation and the analysis is a technical team based out of Princeton and Dave Hilt, director of compliance ant NERC has been the leader of that investigation team and he's going to open with a few comments and I think you can probably do it from there Dave.

MR. HILT: Thank you and welcome. I'm very happy to see a very good turnout, I think, today for the technical conference. We've spent quite a bit of time obviously looking at this event as I've talked to a number of people this was needless to say a very, very large scale event. There were thousands and thousands of discrete events to take a look at in terms of evaluating this blackout. It was a very, very large challenge.

I just thought I'd start off by putting up some of the statistics. Many of these are out of the report so they are available. But certainly it was reported to have affected on the order of 50 million people. We know that there was between 60 and 65,000 megawatts of load initially interrupted as a result of this blackout that represents approximately 11 percent of the entire Eastern interconnection which is a very large interconnection. It is the largest -- 531 at least generators that we've identified that tripped 261 different generating plants.

So that's very, very large numbers of control systems, systems that operated during this event that we're certainly wanting to take a look at, look at recommendations for from the time that the Sama Star line tripped at approximately 4:06 p.m. the blackout was essentially complete by 4:13 p.m. That gives you the time frames of how quickly some things happened here.

So there's a lot of technical areas to be looked at in just that very short period of time as to how systems responded et cetera. The actual high speed cascading of the system when it really ramped up, it began to ramp up of course after the Sama Star line trip and then following that it ramped up even quicker as things progress through Michigan and ultimately on around into New York.

But the high speed cascading was about a 12 second time frame. So that's very fast. And as I said thousands of discrete events and we spent just a huge amount of time. I know that the folks that were working on the sequence of events trying to coordinate and identify the actual sequence and looking at the time stamping that that was a very, very large job to sort all of that out.

Go ahead Gerry.

(Slide.)

This was how we had organized it. Many of you have seen this and I won't go into it but we had actually broken the task up into areas of technical expertise where we could bring experts in from various disciplines including generation, transmission, system planning and design -- all the various key areas that we have industry experts in the field, a number of them came in, their time was volunteered so we had a whole host of volunteers from all over North America including the U.S. and Canada participating in all of these various teams that dug into the black out.

Go ahead Gerry.

(Slide.)

NERC early on issued some near term actions and some of these things we expect to see some further recommendations on all of these going forward. These were some things that we identified earlier and I'll go into how we got to some of those but certainly voltage and reactive management is a key issue insuring that there's adequate voltage support -- we hope to hear some more about those things as we go forward and whether there's recommendations needed for those.

Communications, reliability communications, certainly we need -- we believed and our board believed that there needed to be some work done to strengthen and implement communications protocols between all of these operating entities. Failures of system monitoring and control functions and systems, certainly we saw some of that and we felt that there needs to be some discussion about what kind of recommendations we may need in those areas.

Go ahead Gerry.

(Slide.)

Emergency action plans, what plans do we have in place to take action when there are system emergencies and what areas do we need to address there? Training for operators, training for emergencies, training for communications et cetera, conducting emergency drills was an area that the NERC board felt needed to be addressed.

And finally vegetation management, looking at our rights of way to make sure that they're clear of obstructions, et cetera.

Those were the six areas that the NERC board felt at their meeting in October were fairly important that we needed to get out early and say we could take a look at.

One of the things that I found interesting was that I went back and we looked at some of the past, you know, the earlier, blackouts and I thought I'd just give you some of the highlights from some of those.

These are some words out of the November 1965 New York blackout, some of the recommendations that came out of that and I won't go through all of these but basically you're going to see that we need the first one is related to tools -- the operator having displays and equipment to monitor the system adequately.

In the '65 blackout there was a recommendation for coordinated programs of automatic load shedding that needed to be established and maintained.

Finally thorough programs and schedules for operator training and retraining need to be rigorously administered and those were some pretty good words that came out of '65.

Go ahead Gerry.

(Slide.)

In '77 we had another blackout in New York. It was noted that the single most important cause of the July '88 power failure was the failure of the system operator to take the necessary action. Again -- emergency preparedness and training came into that area. From that make a thorough re-evaluation of the selection and training of system operators so we've heard training now in at least two of these blackouts and a fullscale simulator should be available to provide the operator personnel with hands-on experience.

So we're looking again at the operators tools that were available before them and the training.

Go ahead Gerry.

(Slide.)

July 2 '96, again reviews the need for security monitor function to monitor operating conditions on a regional scale and promote interconnected system reliability. Somebody who has the tools to monitor the system in a wide area to determine what's going on, review the need for tools such as on-line power pull and stability program in real time.

Again we're talking about things that we're providing to the operators out there to do their job.

And finally review the process for assessing potential voltage instability and the need to enhance existing operator training programs and tools.

So again we've got a lot of the same themes I see in some of these. These aren't all of the recommendations that I'm obviously just pulling some of them out. Go ahead.

(Slide.)

August 10 '96, again development periodic review of reactive margin -- that's something that we've heard some things about here -- coordination among regional members with neighbors and with their neighboring systems. Again communications, developing communications systems and displays that give operators immediate information on changes in the status of major components on neighboring systems, again monitoring tools to be able to see what's going on, strongly encourage operators to exercise their authority and finally train operators again so we're seeing a lot of the same themes in at least in some of these areas pop up in many of the blackouts.

Go ahead Gerry.

(Slide.)

Today you're going to have some panelists that were involved with the blackout investigation that are here to listen to hear some of your recommendations regarding moving forward and I'm going to highlight the key areas that I think we have selected, some of the panelists from.

Certainly this operation tools, SCADA/EMS communications and operations planning -- this really covers the gamut of operations and you're going to have folks here from those -- from that panel or from that investigation team who can and are here to hear your recommendations and see what we may need to do going forward to prevent future blackouts in that area.

And Gerry?

(Slide.)

System modeling and simulation analysis and system planning and design. There's been a huge effort underway to build computer models and model what happened on August 14. Much of that has been done up through all of the what we would call "steady state modeling" the load flow modeling. THe teams are in to the dynamic modeling looking at the dynamics phase of this. That's a huge effort.

There was a very large dynamic event a number of events actually where the system broke apart, reclosed back together, so it's going to take some serious time to complete that analysis.

But they're also here, particularly the system planning and design team with regard to looking at voltage reactive management, some of the issues that you saw there. THey will be here as well to look for your recommendations.

Okay Gerry.

(Slide.)

Transmission system performance, protection and controls -- although we did not see significant missed operations of system protection, we're also looking for what do we need to do in terms of the transmission system from a technical standpoint to help us protect it from blackouts. Also generation performance protection and controls -- as you saw earlier there were many, many generators that tripped during this event, some were, they tripped for a variety of reasons, everything from over excitation to just basically loss of the load on the generator. So we saw many, many different trips, over frequency, under frequency, just about every kind of operation that you can identify was in this -- blackout.

So we need to take a look at what we need to do with generation systems, their performance, their protection, their controls, and so we're looking for any recommendations that the industry may have on these two areas.

Go ahead Gerry.

(Slide.)

So what we're trying to do here is not so much as David Meyer noted we are interested in comments on the report hopefully on the interim report or the DOE certainly is, I know the U.S. - Canada task force is, but what we're trying to do here today is we're trying to look forward and say what do we need to do now that we have this information in front of us of what happened on August 14 -- what do we need to do now to prevent these future blackouts? What types of new standards, procedures and protocols may be necessary?

What existing technologies? There's a lot of existing technology out there for things that could potentially be applied to the system that may not have been that should be considered, what new technology should be considered for implementation in the industry to prevent these types of blackouts from occurring in the future, what types of changes in system planning and design assessment do we need to be doing in the industry as a whole and changes to operate, to operator tools and training programs, what kinds of things are there -- just some of the areas that we're looking for input on and we're open to looking at any other areas that I may not have included on this slide.

The key to it though as I went back through the previous blackouts is it has to be implemented. And I think we're going, as an industry, I personally thing we're going to need some monitoring mechanisms in place for whatever recommendations the industry comes forth with to present, to prevent these types of blackouts that there'll need to be some monitoring mechanisms in place to monitor that progress of implementation to assure that we really do implement the recommendations and follow through on what we need to do.

Go ahead Gerry.

(Slide.)

Standards, which is certainly NERC's area and we're very interested in that. Presently we have operating policies and planning standards. Today we have a new standards process in place in developing reliability standards. It's an open process. All interested parties can vote on it, can participate in the ballot bodies, so I'm going to make a plug here for everyone that's involved in looking forward in solving solutions, in finding solutions to the blackout that we need to be involved in the new process and make sure that we're working to get appropriate standards in place if they're not in place.

Looking at what standards need to be developed, we are going to continue to look at other violations of standards that may have occurred during the blackout and what areas that need to be addressed through new and improved standards.

I think there's one more Gerry.

(Slide.)

As we noted, as I am sure everyone in this room has read the interim report, it's available on both the DOE and the U.S. - Canada task force sites as well as at NERC. We're in the process now of working with the U.S. - Canada task force in developing the final report on NERC's role. Our role remains involved with the technical evaluation, the technical investigation, of what happened and why things happened. NERC may well also submit recommendations into the process but today the entire task force is looking for recommendations particularly related to the technical area as we move forward -- how do we solve this and we're seeking that input today.

So with that, Gerry, I think I'm finished.

I look forward to the discussions today and we will, may be, asking the other panelists up here questions as well. Thank you.

MR. CAULEY: Okay, Dave did a good job of introducing the conference and what we're here about today. Thanks a lot.

Essentially if you go back and look at the report that was issued on November 19, the report is very factually based and narrowly focuses I think on the direct and immediate causes of the blackout and tries to explain that in a lay person language that is easily understood by the public, by policy makers in Washington, in Ottawa and elsewhere, and just generally anyone who had an interest or was impacted by the blackout.

Because the report was so simply stated, so simply and directly stated, doesn't mean that there was not a lot of technical detailed analysis behind it and I assure you there was and I think we are fortunate today that we have a number of the team leaders here who will be able to speak on various panels and go into a bit more detail about the analysis and where potentially it can lead in terms of developing a final set of lessons learned and recommendations.

So that's where we're headed in this next phase. There are a lot of people I think on the U.S. - Canada task force as well as the technical investigation teams supporting them, to really figure out what went wrong and to make sure this doesn't happen again, at least in our time on our watch, that something like this doesn't happen again.

So you can point to some very direct and immediate causes if you go back and reconstruct the time line and what happened, who said what to whom on August 14? What we're about now is what went on behind the scenes to allow that to happen? Why did that happen? Why was it allowed to happen?

It gets into issues of are the standards adequate? Are the standards being enforced? Are we studying the right thing on the system, both regionally, nationally, gridwise and locally?

Do we have voltage problems or do we not have voltage problems? We can point at one level to exactly what happened but you look underneath that there's a whole set of issues that arise that we need to deal with and we're hoping to deal with that in the next month to two months as we develop the final report and a set of recommendations.

The inputs from this group today are very important. This conference is being transcribed and I assure you that all your comments will be directly reviewed by the team leaders as well as the U.S. - Canada task force and your comments are important in formulating the lessons and recommendations learned in the final report.

We have five panels set up in five technical areas, the first being reliability coordination. Obviously we may have thought beforehand that we had a good view of the system and good coordination of reliability among reliability coordinators and with operating systems and control areas. The events of August 14 point to a substantial breakdown in those assumptions in terms of what was actually happening.

So we have a panel, the first panel up here, A, will deal with some of the reliability coordination issues.

Then we move to a panel on emergency response, the ability of operating personnel and reliability coordinators to recognize emergencies, act decisively, have the authority to take action when needed to prevent catastrophic failure of the grid.

The incidents on August 14 point to shortcomings in the area of operator tools, our ability to see the big picture, our ability to understand what's going on in the system, many of these things Dave Hilt pointed out were learned in prior blackouts and we need to ask ourselves -- why are these tools that should be available not available and being used -- and what new tools and technologies would help us provide a better set of information for the operators and reliability coordinators.

Panel D, we're looking at system analysis and study. There's been a lot of conjecture about what actually happened in the blackout, what caused it? Was it a voltage collages, was it not? We'll have some input from the team leads and some panelists to talk about those issues.

I think more importantly there are two aspects of panel D, there were some very interesting phenomena that occurred during the actual cascade. We did eventually as the cascade progressed get into frequency collapse and voltage collapse and significant power swings and those kinds of things. The question is, if we do have a major disturbance on the system in the future, how can we keep it from propagating throughout the rest of the system?

So how can we design the system better, operate it better, so that we don't allow that kind of system to rip apart and collapse as it did in this case?

And finally panel E we're looking at protections and controls, transmission protection, both the mundane protection we have for lines and transformers and so on but also more advanced types of schemes that might help protect the system and limit the propagation of cascading outages, as well as generation protection -- did the generators participate as they should have? Is there a way we can improve generation response during severe perturbed system conditions, and can we more effectively coordinate transmission and generation protection as well as load reduction schemes that might be possible?

So that's what we're going to try to do today.

Next slide.

(Slide.)

In terms of format, we first off I want to express my appreciation not only for this panel but for all five panels, the folks that volunteered, some volunteered more than others, but they're all here, so we thank them.

We appreciate their taking the time to put some thought into a set of recommendations in their perspective of what needs to be done to operate the system better in the future.

Each panel will speak one at a time. We'll go down the row as we see them here. We also have a team lead speak to that set of issues, in this case it will be Don Benjamin from the NERC staff -- once the speakers have made their short presentations the panel will be subject to questions from the investigation team and then also we will open it up to the audience.

And I encourage you, if you made all the effort to get here, I encourage you to step up to the mike, ask your questions, make comments, because it's not just the formal presentations it's the comments from the audience that will make the difference in formulating the recommendations. We're still very early in the stages of developing recommendations, do not have a "road map" do not have a set of plans in terms of what those recommendations are. Please, you're here, let's hear your inputs, and get those ideas for what those recommendations should be.

Just a couple rules and I will enforce these lightly, unobtrusively but when I do if I need to I will. First off, we're not going to get into any business, anti-trust issues, discussions of market pricing or anything like that, just basic anti-trust stuff. I'm not a lawyer but I can smell it if I hear it.

We're going to focus on broad technical issues of relevance to the industry. We're not here to correct the behavior of any one entity or party or point ont the shortcomings of individual parties' report of November 19 says what it says. We're not here to prove or disprove that. It stands on its own.

If you have comments on the validity of that or any other facts you'd like to present to the task force, I encourage you to submit that in writing.

Today is about what we can do as an industry to operate the system better in terms of all these technical aspects and we'd like to be proactive, constructive -- what can we do better?

Next slide.

(Slide.)

There is a one-way audio feed so even though we have a good number of folks in the room, there are many more, I suspect hundreds, listening in on an audio webcast available from a link from the NERC website and we appreciate those folks listening in.

Unfortunately we didn't get high tech enough to allow them to interact and submit questions but they can listen in to the discussions and they can submit written comments to the Task Force after the conference.

There is a transcriber as I mentioned in the back and we will publish a set of transcribed notes from the meeting and I encourage you to submit written comments. There are two places you can do that, one representing Canada and one representing the U.S. and my understanding is it's a shared pool of comments and both the U.S> and Canada will share those comments so it's really up to you which is more convenient as to where you post your comments.

And for those of you familiar with NERC meetings, this meeting is sponsored, technically is hosted by FERC and I think we found somebody who provides less food and refreshments at a meeting than NERC. Because today we will have coffee at the morning break and the afternoon break but lunch will be on your own and we'll try to give you sufficient time. There are several restaurants in the hotel or just outside so we'll -- unfortunately we can't service that today but we'll give you sufficient time to get in and out and come back for the afternoon session.

That is it, I think that's my last slide -- okay, with that we will start and go ahead with the panel.

Any administrative or logistical questions before we go, before starting with the first panel? Okay, good.

We'll start off with the first panel. This one is focused on reliability coordination, a function that was sponsored by NERC and initiated recently in the last few years particularly after the '96 blackout and we'll start with Michael Calimano from the New York ISO. You can speak from there or here. It's your choice.

MR. CALIMANO: I'll speak from here. I guess when we saw the list of questions and the time frame on it it is a quick overview of what I saw going on and a couple of points that I wanted to see going forward on it.

For what lessons learned on it -- Gerry, next slide --

(Slide)

-- it really focuses on a reliability coordinator for us to see a wide area within a coordination area. A reliability coordinator needs to see enough of it not necessarily flow gates for scheduling purposes but it has to see how the system operates. Let's understand that.

We can do that with various bits of data. A lot of this stuff already exists in some form or another, but it puts another set of eyes on real-time operation of the system.

The other point I wanted to point out was the RC with the control area and I guess we're kind of different at least in New York where we have transmission operators who monitor transmission within their local control -- local areas. The New York ISO monitors the entire state on a volt power system and the ability to look into individual transmission systems.

But they've got to be capable of monitoring each other and backing up each other. Case in point -- I thank Gerry for showing the '65 blackout and the '77 blackout in New York -- clearly there were a lot of lessons learned from those two. One is the understanding especially in '77 somebody understanding from another, from a broad perspective, what's going on when you may not have all the information. And this is what happens most times in blackout situations.

The operators don't have all the information and have to rely on somebody else to let them know what's going on and take direction from each other.

Next slide?

(Slide.)

Reliability coordination needs to have authority in real time to order actions to be taken by control areas or operators under emergency conditions. It has to be spelled out well beforehand. You can't get into a discussion at the time and it can't be a request.

It's an order and an order takes action and you call up and follow up afterwards with any discussions on it, was it the right order or not, but clearly in a real time situation, action has to be taken, has to be spelled out, and noted. This has to be worked out well before the emergency, people have to understand who's in charge and when, and what actions they can do and cannot do on it.

I think efficient communication with surrounding control areas, reliability coordinators, we have methods of doing that. They're slow, they're inefficient -- they're good if you're into a capacity shortage as you are planning for a few hours ahead and you can alert the world to that.

In real time it's difficult and it's difficult because in real time they're up to their eyeballs trying to solve the problem.

We have to look at how we can do this better, how we can let other people know better and faster and in our shop, when there is an emergency going, everybody's involved and to solve the emergency and the communication comes later.

I think we got to work as a group to be able to effectively do the communication why we're in the emergency and so we get the word out as quickly as possible on it. I think that's indicative of everybody's situation.

One of the questions was should we share between reliability coordination -- and share redundancy? I keep coming back to the clear lines of communication and clear lines of authority -- it's necessary to know who, point by point, is going to take actions under what conditions and who's going to make a request for changes and who's going to make an order for changes.

That procedure, that protocol, has to be worked out well before that so people know what page they're on when they're talking with each other on it. If a reliability coordinator declares an emergency, whatever criteria one uses to declare emergencies -- we have a major emergency terminology in New York.

But once he declares it then it becomes command and control right away and action is taken. What I'm looking for is that ability spelled out across the board as whatever the term for emergency from your reliability coordinator, that those actions that now define that now we are in this emergency condition, these are the things that you will follow on with an order to either redispatch, take voltage reductions, load shedding, what have you -- they become orders, orders have to be followed, can be discussed later but they have to be followed at the time the order is given.

I think monitoring the critical facilities of neighboring control areas, this is an area that I constantly get asked about myself, how far into PJM, how far into Ontario, how far into ECAR do we see -- and is it important and will it give me an early warning system?

I think some of the things came out was that maybe we should monitor the Lake Erie loop in different locations on it. I believe there's sufficient data out there and on the network and in the ISM that everybody can get into a monitoring position but I'm not sure what I would monitor in someone else's area unless I got that information back from them.

These are the critical interfaces. This will tell you what's going on on the system. This will give you a good overall view of what is happening in the system.

I think we have the capability of doing that now. That's the near term fix. I think we can expand that but my only issue is staffing and requirements to be able to monitor this on a regular 24 x 7 basis. I think all our operators have full time jobs now so asking how to do this is another question.

But I think we can do it with relative ease of work in getting the data into us. I think we have to be, the reliability coordinator, has to be staffed at 24 x 7 to allow the system to be securely operated -- all the time with the information both internal and external, and notification.

So I see two areas that need and usually fall into generally a limitation on staffing but the key things are coordination notification with other reliability coordinators and the ability to monitor other systems outside their own far enough in to at least give them an early warning system.

I think those are the key areas on that.

There are numerous articles as to how well we are coordinated in the Eastern interconnection -- I'll save the Western for Mark -- but I think there's an ability here between NERC and the regions to look widespread and what we can do under certain controlled high-risk conditions.

One of the things that keeps coming out is how do we make your system safe or how do you get to a more conservative operation condition when something is happening somewhere else? If it's an unknown, I want to know how it impacts our system and I think from a systemwide point of view, those are the large scale systems that we take a look at.

I believe the emergency operating procedures should exist between reliability coordinators, that they know what actions the other one is going to take and have agreed upon that -- this is more than just your internal looking at it. This would be a reliability coordinator emergency conditions say between New York and the IMO.

If we have an incident here, what do we do -- what do you do, and how do we ensure that we know what each other is doing on that?

My final pitch is the functional model. The NERC reliability function model -- describes the functions of various authorities or entities running the system and planning the system but there is no clearly defined relationship between those functions and I think, as we go forward in developing the standards, we have to define those relationships better so people know that going forward how this operates -- the best I can do is say we've defined the functions. Now we have to define the relationships and that's got to go forward.

I hope I used my seven minutes but I wanted to keep it short and brief.

MR. CAULEY: Thanks Mike.

Next is Mark Fidrych, who is from the Western Area Power Authority and also the chairman of the NERC operating committee.

MR. FIDRYCH: Good morning.

As Gerry said, my name is Mark Fidrych. I work for Western Area Power Administration and I'm presently chair of the NERC operating committee.

By way of background, I spent six years as the operations manager for Western and five as the reliability coordinator manager in the Rocky Mountain Desert Southwest region of WECC.

I'd like to address questions one and three today and wrap up with a response to question six. I'll try to keep my remarks brief and allow time for questions.

First question, 'what lessons are learned from the August 14th outage reliability coordination and what recommendations are there to improve reliability coordination?'

Let me begin with a short philosophical digression on power system operations evolution. I know some have heard me say this a few times before and I apologize for repeating.

In the days of vertical integration most operators had a signal place to go for an answer and while those answers weren't always the most economical for all they generally tended to be somewhat conservative since the last thing a chief dispatcher wanted to do is lose load.

But what took place simultaneously was the development of familiar working relationships between neighboring entities and those relationships evolved over many years and frequently not without a lot of management support.

Even looking at presently developing markets, and I have to catch my place here --

(Pause)

-- okay, I've seen similarities. PJM has a very functional market that evolved over many years. THey started small and loose and then gradually developed -- as new needs came up they developed new programs. LMP I am sure was not radically implemented overnight but they were able to put it in place because it was the next agreed upon solution for their market and they had a base of working relationships.

With complex organizations you cannot implement 100 things at once dealing with multiple outside organizations as well as multiple regulatory organizations and hope to have the same outcome as a mature organization.

Reliability is always going to suffer when you try to change too many things simultaneously.

So how does this fit with August 14th? Of the issues directly related to reliability coordinators there were three prevailing themes, communication, monitoring and assessment. These are not dissimilar to the conclusions in the '96 report in the West. Four of those conclusions were to emphasize security, expand scope of analysis, improve reliability information and strengthen operator training and readiness.

The scenarios were slightly different but we see the same issues again being problematic. What do we do to improve? I think that there needs to be a greater sharing of accurate data among all companies and that extends to planning and outage data that's used to develop contingency analysis.

Companies have got to be committed to aggressively updating their data via whatever exchange media can be implemented whether it be ISN or some other method -- and maintaining reliable data links for those exchanges.

Second, there needs to be exchange programs among the reliability coordinators, i.e., working visits to the neighboring areas, the neighboring reliability coordinators, to promote the personal relationships as well as to the subordinate control areas on an ongoing basis.

Finally, analyses have got to be spread widely among entities to increase the number of eyes having visibility to developing situations.

The third question asks, 'should these reliability functions be shared overlapping between reliability coordinators and their member systems to assure redundancy or should these responsibilities and authorities be divided between reliability coordinators and member systems -- if so, how should they be divided?'

Yes, they should be shared. It just matters how they're shared. For the member systems to buy into the process and the analysis they need to participate. I think however that the size of the member system and its impact on the interconnected system and vice-versa, will dictate the commitment that they will make.

But I don't believe that we can live with delegating any of those responsibilities from the reliability coordinator. This is analogous with my vertical utility -- there has to be an entity responsible for a specific area and the operation of that area.

Again, multiple eyes are better, but for seeing and communicating -- not for directing.

This does not however address the issues of wide area versus local reliability responsibilities. I expect that they will continue to exist for some time but should not pose a problem operationally.

So in conclusion let me address the last question, what recommendations are there to ensure the basic reliability safeguards noted in chapter two of the Interim Report?

Back in '96 when the first regional reliability plans were being developed we had ideas about what should be in these plans and for a while that worked, because we were busy implementing those plans and were focused.

But then as we began to reorganize the industry we became focused on a new task at hand. There were new liaisons being formed that were much different than those of the past. Reliability plans were being changed to reflect again how it was going to be done, not the tools and procedures presently in effect.

We need to refocus on the reliability plans but not to allow changes that affect reliability to move forward until all the pieces are in place and the system has been demonstrated effective.

We have to develop a greater standardization to our methods and our reviews. We have to broaden the visibility to what is happening on the system to many and that includes all system parameters including generation. We need to put our bright people to work and have them develop systems which will give accurate status of the vulnerability of the power system stability or we reduce system transfers to a level where we are confident that the system is not in jeopardy.

At this point I will add the usual caveat that this list is not all-encompassing but, if we start with the aforementioned items, we will be going a long way toward embracing the concepts that were so well put in chapter two of the Report.

Thank you.

MR. CAULEY: Thanks Mark.

Just in case you're wondering, there was a published agenda with the speakers, with the questions posed to each panel and in case you're wondering where that is, there are copies of the agenda on the back table there in the back of the room, and those are the questions that the speakers are referencing.

Linda Campbell is with the Florida Reliability Coordinating Council. She will be the next speaker.

MS. CAMPBELL: Thank you Gerry.

Good morning everyone. I have to say I am very honored to be on this panel this morning and speaking to you on the subject of reliability coordination.

The focus of my presentation is going to review all of the questions that were in the agenda conference materials, share FRCC thoughts and recommendations on each of these questions and I guess ultimately the bottom line I'd like to do is kind of remind the industry that, in our search for solutions we often try to find easily a one size fits all answer.

I want us to really be careful in not do that with this. I don't think that that is necessarily the best way to go.

Gerry, next slide please?

(Slide.)

Actually one more --

(Slide)

-- okay, one of the questions that started off was 'what are the lessons learned from the blackout regarding reliability coordination?' I think the primarily key lesson that we believe is important is the review of reliability plans. Mark was a good lead in for me on this.

I really believe that comprehensive reliability plans are needed. It needs to provide wide area oversight for the region or the reliability area and there needs to be a very thorough understanding by all parties, not only the reliability coordinator but all of the operating entities that are under the purview of that reliability coordinator.

Reliability plans often we believe should have a common format. This would help reduce inconsistencies between the different reliability coordinator operations.

That does not necessarily mean that every reliability plan will look the same and be a cookie-cutter but at least every reliability plan should follow some sort of a checklist so that they've asked themselves the same questions and then they can take the appropriate action if that's appropriate for their area.

Reliability plans must provide the authority that is needed for the reliability coordinator to direct actions and this reliability plan should also make the obligation of the operating entities to implement those actions.

Those are all very important and key to any effective reliability plan.

Next slide?

(Slide.)

I'd like to share with you a little bit about the FRCC reliability plan. Our geographic peninsula has mandated or necessitated a lot of coordination cooperation for many many years between all of the operating entities.

We've got over 30 years of experience working together in this area.

Our reliability plan was first developed in 1996. We did a major overhaul of it in 2001 and we've revised it again in 2003. All of the operating entities in the region understand and follow the reliability plan and even if there is a dispute sort of as Mike mentioned, the reliability coordinator will direct an action and if there is any dispute about that direct, then they will talk about it later -- but they will implement the actions of the reliability coordinator at that time.

We review, update and revise this as change and we believe that there are probably many reliability plans in the nation -- the country -- that would be able to serve as role models but we also believe that perhaps the FRCC security process or reliability plan could help serve as a model as well.

The FRCC reliability plan identifies and outlines a reliability coordinator responsibility. It provides the authority for them to direct specific actions. We also describe the procedures that must be used for monitoring and analysis. This would cover real time operations, operations planning and emergency conditions.

It also identifies requirements for information exchange, communication and back up capability. We do have an established back up reliability coordinator that's ready to take over upon a minute's notice. And so we've got all of this identified within our reliability plan.

Our reliability plan also identifies operating entity responsibilities. We didn't think that the plan is complete if it only talked about reliability coordinative responsibilities. You've got to address what the operating entities also must do.

It also provides the directive that the operating entities will implement any directions given by the reliability coordinator under normal and emergency conditions and it requires the operating entities to provide all the necessary data, real time data, operations planning data.

Operations planning data would include maintenance plans, equipment status -- all of that kind of information which is important to the assessment and monitoring of the system. It also identifies the requirements for information exchange and communication and this is not only with the reliability coordinator but with each other, all of the control areas and operating entities within the region.

The next question that was in the package was 'what reliability coordinator functions and tools are essential for safeguarding reliability?'

We believe it is absolutely necessary for an accurate state estimator model along with a contingency analysis program to be working and in order at all times. We believe it should run at least every five minutes. This will capture any changing conditions so that if a particular line goes out or anything that is going on can be assessed and monitored and you don't have to think about going and pushing a button necessarily to check it out. It's got to include critical facilities in both the reliability coordinator area and the surrounding reliability areas.

The accuracy of this data is imperative to the solution of these cases and it takes a lot of effort and a lot of manpower to keep that data going and to make sure that it's appropriate and free flowing.

We have our own data exchange working group that has the responsibility of keeping that real time data sharing procedure in place and operating effectively.

We do have both a state estimator and a contingency analysis model that runs every five minutes. We look at over 700 contingencies. We do monitor facilities within our neighboring system, the Southern Company system, we've got over 20 lines and 11 units that we believe, if there were problems with, would directly impact the FRCC region -- or if the region had problems they could directly impact the Southern Company system and we have communication back and forth between the Southern Company or the sub region reliability coordinator -- with ours.

So the output of this determines any action that the reliability coordinator would need to take.

Again, for essential tools and functions we believe operations planning analysis is very imperative as well. We do a next day study every day, weekly studies twice a week and monthly studies once a week. This data is shared with each entity, reliability entity, in the region. They can use this to develop ATC cases. But they are updated on a daily basis with maintenance data, scheduled maintenance outages, unscheduled maintenance outages.

The PTR load flow models should be utilized to do this and this provides us this heads-up look for the next day or even the next week so that if you see conditions that may be popping up that will provide time to be able to deal with them effectively on a proactive basis.

And the last thing regarding tools and functions is effective communications and that needs to be under normal and emergency conditions. You need to have internal communications procedures within the organizations themselves, external outside, and then the key about it is it's got to be timely with everyone.

In the FRCC we have an internet communication system that we call the "FRCC net" -- it's a frame relay system. We share real time data through that system. We have a messaging capability with that. We also have a hot line phone system with all the operating entities in the region and I think that's a very effective tool.

This allows all of the operating entities to hear the same thing at the same time. It keeps them abreast of what's going on even in the neighboring system so there are no hidden conditions that are really going on.

And we also have a back up satellite phone network that can take the place of the hot line should it go down. We actually put that in with Y2K but we've kept it around because we believe it's an important back up communication tool.

The next question I wanted to address is should these reliability functions be shared or divided? We don't think so. We think that the wide area overview needs to be provided by a single reliability coordinator for that area.

Redundancy in the functions, the sharing of that can be beneficial and can be good. But the directives of the reliability coordinator must prevail and you can only get that from having one entity.

In the FRCC we do have three other control areas that run state estimator and contingency analysis on a periodic basis as well. So we do have that extra set of eyes out there looking at the same things that can provide a sanity check for our reliability coordinator.

So they are beneficial but ultimately the decision making has to be by one entity so that there are never any questions about that authority or the directives given.

'Has the wide area overview been implemented effectively in industry -- why or why not?'

Well, we don't think so. Obviously there's a, it's been very effective in some areas of the country but as evidenced by the blackout, maybe not in all. We believe that the NERC review of reliability plans is maybe not thorough enough. Perhaps there needs to be a little more NERC oversight of that in getting into that more so there can be a common structure for the plans.

The term 'wide area' can mean many things to many people. We're seeing that in the development of standards, trying to look at local area, wide area -- so that may cause some problems when people are trying to figure these things out.

But the key to all of this is that review of these plans has got to be an essential part of this to make sure that all the key parts and pieces of the reliability process have been included and covered.

Along with the review of these plans it may be important to include some more stringent auditing to make sure that reliability coordinators are actually implementing the plans as they are written. In FRCC we do reliability coordinator audits at least every two years and we've done that for many years now. And we make sure that the reliability coordinator is implementing the plan as we have written and agreed.

'Are the size and number of the liability coordinators in control areas factors in determining effectiveness -- if so, how?'

We don't believe that that's really the issue. Complex geographic interfaces will or could be a problem in some areas but we really don't think that the answer lies in just limiting the numbers of either of those.

We've got 11 control areas and over 20 operating entities and I believe that the key to our success has always been the data sharing capability, our reliability processes in place and the coordination of all the operating entities and the coordination with our neighboring sub regions.

It's really important to determine what needs to be shared, what needs to be monitored, how to do it and, once you figure all that out, you can make it happen so it really isn't just how many reliability coordinators or control areas that are the answer.

The last line is, 'what recommendations are there to ensure the basic reliability safeguards noted in the Report are effective?'

I believe the comments to the questions provided already have given you some idea of what our recommendations might be. I want to emphasize that -- one size fits all is not the answer, that there are many areas that are doing a good job right now. Perhaps we need to learn from those areas and take from that before we go to try to figure out something like the whole world is broken.

The FRCC does believe that NERC should play a bigger role in developing the structure and the review and implementation of the reliability plans. This will be a key in operating reliability going forward and that the plans need to be able to address any number of configurations of reliability coordinators in the entities within their purview. It's not just a magic size or form but it's all the key parts and pieces are there. It really doesn't matter what they look like.

Thank you.

MR. CAULEY: Okay for speakers for the rest of the day, that's as long as you can go without me jumping on you.

MS. CAMPBELL: Sorry.

MR. CAULEY: The last -- we have one more panelist and then Don Benjamin has a couple comments on the functional model but Mike Kormos is here representing PJM.

MR. KORMOS: Thank you and good morning. And I will try to keep my comments brief. I'm going to repeat a lot of the same themes that my colleagues did up here.

First slide Gerry.

(Slide.)

As far as the lessons learned, I think what was most troublesome to me was really as reliability coordinators we need to go back to the basics. We need to go back to looking at really what I believe to be some fundamental system operations basics regarding system monitoring, the operator awareness, being able to continue a system plan for an N - 1 and knowing where your system was and then obviously the internal and external communications.

I really thing we need to take a step back and really look at what we're doing and how we're doing them and the tools we're using to do that.

The second point again which was troublesome is just in redundancy, not only just in the computer hardware and software but also the redundancy in having more than one set of eyes looking at specific areas, and I think, as many of my speakers have talked about, many areas in the country are set up this way and I think it's something that should be required to have that kind of overlap is really I think a good fail safe as part of the system.

Emergency preparedness again has been talked about. It needs to be clear up front, the actions that can be taken, the actions that will be taken, what the procedures are, who has the authority to take it. Again, I think that needs to be absolutely clear cut in the minds of all.

So to continue on the theme, I think again since these are all things I would have thought had already been in place, we really need to take a hard look at how we're doing the evaluation of that. It's one thing to put it down on paper in a reliability plan but we really need to make sure we are in fact doing what the plan says, that the tools that are there are supporting that and I really thing that a third party critical evaluation, I think we have to learn and maybe we can learn from other industries of how to do a critical evaluation whether it's an independent or a peer review is really important for moving forward.

Next slide, Ger --

(Slide)

-- question on the tools that are essential -- and I actually won't go into that now having heard Linda's because I think Linda really covered a lot of the tools that I believe are really important for reliability coordinators, the real time monitoring and alarming.

I think we have to challenge ourselves as to what is exactly real time? I think we've been way too loose on that definition. The visualization tools, wide area looks are, I think, the appropriate thing to do but it's also difficult to do and you really need to have strong tools to be able to look over these wide areas to assess all that data and convert it into something useful.

Real time security analysis contingency analysis again I think we have to challenge what the definition really means and how it has to be implemented and then the redundancy in the multiple levels of monitoring and analysis.

The 'whether the function should be overlapped' -- I personally thing overlapping is critical to have fail safes in this industry. We've learned hard lessons. Any one of our systems can fail. None of us is perfect and having that overlap I think is critical.

We're very much like Florida and New York, the previous speakers. We use what we term the 'hierarchical model of control' which basically overlays with PJM, our transmission owners, all our transmission owners, and PJM are running full blown, state estimator contingency analysis, they are extremely good at it and they are critical for working with us and helping us, backing us up in assessing the state of the system at all times and I think that's really important.

Also I think overlapping between reliability coordinators is a good thing but it's more of a dangerous thing. As we have all talked about, having clear authority and responsibility is important.

We'd been working very hard with MISO prior to the blackout as well as obviously after it, to lay out and delineate what those responsibilities will be between us.

There needs to be or will be overlap between our systems. We've developed the joint operating agreement, we believe it is a very good start but setting out those obligations responsibility is not the end all and I think we will continue working very hard to try to continue making that a better product.

The last one, we'll take off a little bit on Mike Kormos' theme. We support the functional model of NERC but we do have concerns as well as I think do our colleagues in NPCC do regarding how those responsibilities are going to be shared, how that overlapping will happen, and really setting up clear lines of authority and responsibility. We really think that needs to be further worked out in the process.

As far as wide area overview hasn't been implemented, again, I can only necessarily talk about if from PJM's perspective, we think we've at least made a good shot at it. We have put in a new state estimator. Since the blackout it's triple the size of our old one. It is a

10,000 bus bottle. We believe it's probably the biggest in the country if not the biggest in the world. We modeled it down extensively from the Atlantic Ocean out to Illinois and actually beyond.

The model includes all of the critical flow gates that we've identified with MISO that we are monitoring now. All of the MISO flow gates that we have been asked to. And we are doing contingency analyses on those as well so there will be an overlap.

Again we needed to have clear responsibility. These are MISO's responsibilities that we will be providing sort of the secondary role for regarding that.

I will warn you though there is a significant cost of inputting that. It cost us over $30 million to make these changes for our market integration and our footprint expansion.

Again we are able to justify that and our members are able to support that because of some of the other benefits of market integration with these costs can get quite expensive.

The next one is 'the size, number and complexity of the reliability.' As far as size goes I just mentioned cost. I do believe size matters. I do believe that you can in fact justify the cost a lot better looking over a much wider area -- it helps minimize those impacts.

Regarding the complexity, we're probably in the middle of this and most people understand that. We've seen that basically complexity is two parts. One is the technical complexity the other is the constituents -- constituency -- I apologize, that's the pain of staying up too late to watch Monday Night Football.

The technical issues have been difficult but resolvable and again as I talked about it I think for the most part we have those handled. We have found ways of being able to model the system, the wide area, as much as the neighbors.

The constituency demands have been much more of a challenge to us though just because of the complexity in there as whether they're governmental, regulatory, obviously commercial issues -- have been the most difficult thing for us to resolve. We understand they do need to be resolved.

But that really has been in our opinion the harder part of resolving some of these complex seams. The technical aspects of it are we think much easier to resolve.

We believe once the geographies are established and the clear authorities and functions are established, that in fact this is something that is doable and resolvable.

The last item again high level, I didn't really go after too much -- 'mandatory reliability standards' we think are critical coming out of this, we need them, we need to make sure they are enforceable. And again sort of the same thing, we really believe NERC and I don't mean just the ladies and gentlemen at Princeton -- the whole NERC community really needs to take a step back, reassess how we are looking at the control area and the reliability audit functions, they really look to make a number of improvements in how we do those evaluations and I support everything with having consistency in our plans but I really think we got to go beyond just looking at a plan by making sure that the plans are being carried out and are capable of being carried out to the full extent.

That concludes my comments.

MR. CAULEY: Okay, thanks Mike.

And then just to close the panel, we have a few remarks from Don Benjamin on the NERC staff regarding the functional model.

MR. BENJAMIN: Thank you Gerry and good morning everybody.

Mike Calimato and I think Mike Kormos and others have referred to the NERC functional model and for those of you who may not know what the NERC functional model is I want to spend just a few moments discussing it with you this morning.

After the Energy Policy Act was passed in the mid

1990s it became quite obvious to the NERC operating committee that as the industry was beginning to unbundle itself and utilities were selling off their transmission assets or their generation assets or whatever and new organizations were forming like ISOs and RTOs and the like, that the basic reliability organization which we have known as the control area for the last 50 years or so was beginning to become difficult to identify and the NERC operating policies that were written to the control area were beginning to lose their focus because what is a control area any more?

And in many cases it was just becoming a balancing organization and didn't have transmission responsibilities.

And so in 1999 the operating committee commissioned a small task force to start looking at the operation of the control area and perhaps take a different view of how NERC policies ought to be written and so what came out of that control area criteria task force as it was called was a concept that NERC should develop a set of functions and then write its operating policies to those functions rather than to write them to any one kind of organization such as a control area, an RTO, an ISO or whatever might be forming in the years to come.

In 2001 the board of trustees approved the NERC functional model and since that time as we have been developing our new reliability standards they have been developed around the functions of that model.

We recently completed an update to the model. We wanted to make sure that the model can accommodate the newer market structures that were forming. We found that the model does indeed incorporate and accommodate markets.

In fact, it's really independent of market structures. It doesn't matter what kind of market is there or whether there is a market at all, the functional model still works.

And up here on the screen are the actual functions themselves and one of the ones that we've been concentrating on today is this one called 'operating reliability.' That's the name of the function and Gerry can go on to the next slide.

(Slide.)

That's the name of the function and what we have identified underneath that is the reliability authority. We call that the 'responsible entity' so organizations, ISOs, RTOs, even control areas regional councils, would -- register with NERC to be the reliability authority for a certain area and as the reliability authority they are responsible for the tasks defined as the operating reliability function, so every function has a responsible entity that goes along with it.

Now the important part of the functional model, at least when it involves or as it relates to the August 14 blackout, is that one of the guiding principles of the model is that an organization that registers to perform one of these functions is responsible for all of the tasks that define that function.

An organization may delegate tasks to other organizations but it cannot delegate its responsibility for ensuring that those tasks are all completed. That's true for the reliability authority, it's true for the balancing authority that will ensure that it will balance within its area, it will be true for the transmission operator, it will be true for all of these functions.

And so the functional model should provide some clarity, should help provide some clarity of who is responsible for doing what? And we hope that that will eliminate potential finger pointing in the future and clarify the responsibilities.

Let us go on one more slide here.

(Slide.)

And I'll end on this one here. One of the points that Mike Calimato and Mike Kormos both made and that I agree with is that you will not find clear delineations of authorities within the functional model. The functional model simply identifies functions, tasks within functions but does not go very deep into the inter relationship among those functions because it is not really intended to do that. Because it's not a physical model. It's just a model function.

There are other documents that NERC is developing that will better define the inter relationships among the functions and the responsibilities of those functions and I want to show those to you here. The functional model is what we've just been talking about and it defines functions as a set of tasks and it also defines responsible entities and goes into some detail but not a lot about the inter relationship between those functional entities.

Each of the organizations that are out there, the control areas, RTOs, ISOs, generators, transmission owners, et cetera, will register with NERC and tell NERC which of these functions it is going to provide. For the reliability authority, the balancing authority, interchange authority and transmission operator, NERC will develop a set of certification criteria and audit those responsibilities to make sure they are capable of performing those functions.

So that will be in the certification procedure here. That is where I believe some of the relationships need to be established. So in other words, the reliability authority when it is certified must be shown that it has the authority over the balancing authorities, over the transmission operators, that it can take whatever action is needed.

Similarly when the transmission operator is certified we need to make sure when the balancing operator, the balancing authority, is certified, NERC needs to make sure that it will operate to the instructions given to it by the reliability authority.

So that's where some of the details need to be included that Mike Calimato and Mike Kormos were talking about, that are very, very important.

The regional reliability plans, we're now developing some of those new templates for those plans, that's what Linda Campbell was talking about. They have a consistent set of reliability plan templates. Those regional plans will identify, designate, list, whichever word you want to use, reliability authorities, to cover that region and the balancing authorities that cover that region, to make sure that there are no gaps or overlaps.

And finally we have the reliability standards themselves, the new NERC reliability standards themselves -- are being written to the responsible entities -- so that the new standards will say 'the reliability authority shall -- the balancing authority shall -- the interchange authority shall -- et cetera.'

They will no longer say 'the control authority shall.'

The reliability standards provide measures of performance and determine the ability that these various organizations have to perform what is in the standards themselves.

So it's all four of these documents together. The functional model, the organization registration and certification requirements, the regional reliability plans and the reliability standards that work together that define the obligations of the responsible entities and their inter relationships.

Thank you very much -- we'll skip this slide here.

(Slide.)

MR. CAULEY: Thanks Tom.

First of all, any questions of the panelists from the distinguished panel investigators?

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MR. MEYER: I have an observation more than a question. It's just that, as we move into the recommendation phase, I am always in the back of my mind it's 'how do we proceed? How do we move the ball forward?'

Recommendations can be posed sometimes in fairly general terms that, as we need to take action in some particular area address some particular set of problems, but that still leaves open the question how are we going to do that and a lot of times the ball is going to have to be carried by various sets of parties depending on the issues.

So when you offer suggestions and comments, give us your ideas on how to move forward on this in an implementation mode. That's important information for us also.

MR. CAULEY: Tom?

MR. RUSNOR: Thank you very much. It's kind of a short time to put up some really intelligent questions but nevertheless it's my view that there is certainly no lack of intelligence or knowledge in how to maintain a reliable power system.

The will to do it in certain areas might need some improving. The will to upgrade the reliability standards about the current floor or ceiling as you wish I think is going to be vital as we move forward in the future.

I'd like to congratulate PJM on making the investment which I think is absolutely critical for more than just PJM but for a lot of areas across North America.

The big issue in my mind is in the absence of legislation, how do we make reliability standards mandatory and how do we ensure that all the responsible and accountable entities are going to abide by them?

Those I think are more policy issues than technical issues but as we move forward I have some doubt that we are going to be uniformly at a level that's acceptable to all of us in North America.

So maybe somebody at NERC or some of the panel members would care to address how we move forward in that area?

There's also I think the issue of, and let me back track a little bit. I've been out of the power system planning and design operating for at least five years since I've retired and probably about 10 years since I actually did some really useful work so I could be out of touch to some degree.

But in my planning days I notice that there are considerable differences in the regional councils' reliability criteria. Is that an issue?

To what level should they be consistent and coordinated? I am not sure that I am in a position to answer that but I would certainly like to see some comment from the audience and from this panel and from other panels on those issues.

Thank you.

MR. CAULEY: Any response? I'm not sure they all require responses but -- go ahead, Mike.

MR. CALIMANO: I'll go first. I'm sure I'll be corrected when I go wrong but as far as regional councils I think that the council will look at its needs and requirements and in the case of MPCC clearly we have more stringent requirements than NERC has in the operating policies.

There are more reasons for that but we've implemented those policies over the years, as Gerry pointed out, MPCC came about because of the '65 blackout. Additional more stringent requirements came out of the '77 blackout.

I think it's up to the regional councils to review that. I think the regional council is closer to the situation and can get more stringent criteria that's necessary for it.

I believe that also in New York City we have other major concerns and we have more stringent requirements in there due to the state, due to the reliability council or within the state, an N - 2 requirement and develop that.

I think you have to let the councils develop the areas where they need more stringency but they should be allowed to do that and they should be allowed to implement either some sort of mechanism to ensure enforcement.

In the MPCC membership agreement it has the word 'mandatory' in it. We do have mandatory requirements in MPCC to meet those more stringent requirements and I think counsels can develop that going forward or whatever the entity is. I think you have that flexibility.

MR. FIDRYCH: I'll take a shot. I think that the reliability plans that we talked about and the regional councils can provide the vehicle for giving some of the mandatory compliance. I think one of the problems that we run into is that we don't have enough of the entities that are described in the functional model as participants in some of those organizations. I think we're going to have to get those involved in it for those to have all of the breadth of function and responsible agencies involved.

In terms of the policies I think where we existed with the NERC policies long ago is we came to a consensus and the policy tended to be the least common denominator.

I think we need to look at the standards that are being developed now and apply a much more stringent requirement in those standards than what we've allowed to get by within the existing policies and the old policies.

I don't at all think that there's anything that would prohibit an organization from requiring a more stringent requirement where there was a local necessity for it but I think we need to beef up the standards in the first place.

MR. CAULEY: Okay, anything else? Dave or anybody?

MR. HILT: I had some questions.

MR. CAULEY: Go ahead.

MR. HILT: Actually I have four of them for the panel and for the group here at large if the people care to address them.

First I'm going to roll into a couple. I'm going to go through them all and I'll just let you answer, to provide whatever you want.

I heard several people talk about wide area monitoring and the difficulties in building large state estimators and I've been there, done that, so I understand what you're going through.

But my question really is for people like Mike and others, have the vendors out there kept up with the tools in terms of providing software and developing tools to help the reliability coordinators to put the packages together, to build large state estimators and contingency analysis packages?

I know some years ago there was work in those areas looking at different solution techniques et cetera to be applied and I think it's just an area I'd like to hear a little bit of discussion on is, is it something that we need to move forward on in terms of an overall recommendation to say there needs to be some additional work done to provide those tools?

Secondly along the same lines of tools in terms of communications, I heard that communications is difficult, it's slow, we need to improve it, you know, we talked about hot lines, et cetera -- has the communications provided us with the tools that we need to do effective communications and, if not, do we need, do we as an industry or we as government and others, need to approach the communications industry and say 'this is a very important, very critical infrastructure and we need better tools to assist us in communicating on reliability emergencies?'

I heard some discussions just now and earlier also about looking at the standards and strengthening the standards.

Mark Fidrych I believe discussed visits between reliability coordinators. Several years ago I attended a conference where I think it was the president of America Air Lines said at the conference that it was an engineering technical conference for the electric industry and he was the keynote speaker and he said, "It's really wonderful you still do this. I don't know that we do that any more." He said, "because we don't do it in the airline industry because it's competitive information and we don't share that information that may be competitive."

Reliability is not competitive. I think everybody needs reliability. We need to know. I think someone else mentioned what it takes to operate this system reliably hasn't changed.

In terms of doing those visits, Mark and I guess others, one of the questions may be, "Do we need to identify some of the best practices that are being done out there among the reliability coordinator folks?" Share those and make sure everyone is learning from what the best practices are and how we can move forward.

I know INPO does this for the nuclear plant operations and such. Maybe we need to do that for the reliability side of the electric industry and I would just be interested in thoughts on that.

And finally we talked a little bit about state of emergency. What is a state of emergency -- identifying what a state of emergency is and communicating that -- I guess I'd be interested in do we have adequate training out there for the operators? Do we really need to provide them with some simulators where they can set down and actually practice on recognizing emergencies, when to take action and what actions to take?

MR. CAULEY: Of course that last question will be addressed in our next panel. But any response to the other three questions?

MARK FIDRYCH: I'll take the third one--

MR. CAULEY: Go ahead.

MR. FIDRYCH: -- since it's fairly quick on the communications and identifying what the best practices.

Dave, when we make the visits in the West we do look at what companies are doing, what the reliability coordinator is doing and I frequently had a coordinator come back and tell me "we got to scrap the way we're doing this because these guys are doing it a whole heck of a lot better."

We didn't presume to try to give that to anybody else -- as long as we were improving the operations within the interconnections we hadn't taken that next step further.

We didn't presume to try to give that to anybody else as long as we were improving the operations within the interconnection we hadn't taken it that next step further. I think it's probably appropriate to do that.

MR. CAULEY: Linda?

MS. CAMPBELL: I'll tackle the communications ones also though more from the perspective of either vendors helping out and I guess Dave, as far as, I don't know that they're not right now but I'll tell you that the big struggle that we've had in dealing with the vendors for our frame relay or FRCT net is getting in to understand the importance of keeping the availability and reliability high on their system because if we're relying on that frame relay for real time data and it's updating every two to four seconds, we can't take a 30 minute outage on that frame relay and so getting the vendors to understand the importance of that has been a challenge.

As far as the hot line goes we've had a hot line system in place for a long, long time and I guess it's a a dinosaur and they don't even offer that service any more and there's a lot of talk about voice over IT and all of this kind of thing.

We're a little reluctant at this point to put all our eggs in one basket to go there yet. So I think there could be improvements from the communication industry to help us.

MR. KORMOS: I'll take a shot at the first two, Dave. Regarding wide area monitoring it's sort of a mixed bag. I think we've had great cooperation from our vendors but it's almost been an R&D effort for us to do multi processing in state estimator, multi threat e-programs.

They're more than willing to work with us but they're also more than willing to charge us a premium almost to make that. I think a $30 million price tag for our latest government effort is a good example so I think in industry we can do a lot to work on some of those techniques and working on some of the solution techniques of how to get wide area models to converge, particularly when convergences are outside of some of your areas.

There is a lot of work that can be done in that area in standardizing and really working towards that so I think as an industry it is an area we can work with. I don't want to fault the vendors though. They're in the business to make money and not necessarily to do R&D unless there's a demand for it. That's part of the problem we've been dealing with.

As far as the communications I guess my take on it is really we just predominantly as an industry rely too much on voice communications and I think that was in the report. We rely way too much on the phone.

There is an inherent delay when you are trying to make phone calls, the information is not going to be passed timely versus where the amount of data -- again we're receiving 40,000 points every three seconds right now for our contingency announcements and their solutions.

We've found that technology, that communications there, we can move that. But we're still hung on everything is still voice and telephone and when I look back at some of what happened with, at least in our areas, some of the delays were just due to people discussing, talking, ultimately coming to a conclusion and then making the phone call -- where that data could have been sent 15 minutes earlier if we automated.

MR. CAULEY: I do want to leave some room for the audience participation here and now's a good time to start that and hopefully you won't be bashful and we welcome comments, recommendations in this area or questions to the panelists and we'll start with Terry Volkman.

And why don't you state your name and your organization so the recorder can get that for us.

MR. VOLKMAN: Terry Volkman at Excel Energy.

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It seems that our reliability coordinators have developed differently over time. Some have come from operators from companies that consistently operate a system that their reliability coordinator (inaudible) and other ones that are built from scratch.

The question is where do you draw the line in operational economics and creation of operational nuances of how they're prepared to operate between what the (inaudible) reliability coordinator versus what belongs in the control center of the transformation owner operator.

The place where you would draw the line and what type of training that the reliability coordinators get to understand those operating nuances.

MR. CAULEY: Unfortunately we have two tight grids up here who probably are not the most qualified to answer that because they do both but maybe you can give us -- Mark, you want to start out?

MR. FIDRYCH: Yes. I'll make one comment. I think the presentation that Linda provided in talking about the reliability plan provides the vehicle for doing a lot of that, Terry. I think that that's where you need to really specify and rather than having the cookie cutter approach that they're all the same, I think that you get the specificity in that plan that enables you to go out and address those particular issues.

Now the level of operator training on the other hand, it's really tough for me to say if you don't get a very seasoned operator that you're going to have a very difficult time putting somebody in place who's going to be able to assimilate the data that they're receiving visually and auditorially and process it in enough time to be making a good decision.

MR. KORMOS: Let me take a shot at it, Gerry. And I am a tight pool.

But I think there's two answers to that. The first is, I think, for authorities and responsibilities the line has to be drawn. I'm not necessarily sure it matters where it's drawn but it needs to be drawn and it needs to be clear who has authority, who has the responsibility and I don't/can't -- I don't think there should be any misunderstanding in that area.

Regarding operational knowledge though which I think was part of your question. I actually think you should never draw a line. I think my transmission owners, their operational knowledge is as good as ours. We overlap each other. I think that overlap is a huge fail safe to the system that we have two very knowledgeable organizations looking at a part of the system making an assessment, backing each other up, working with each other.

You'd be amazed at some of the discussions we have and I think that that kind of line shouldn't be drawn. You want that overlap. I think it's good for the system.

MR. CALIMANO: I just want to quickly go a little bit further as having the operators work together. In New York the operators do have twice a year a week of training that they do work with the local operators to get that understanding transfer of information, talking -- I think we've mentioned that. You got to get out and see how the other guys are doing it.

MR. CAULEY: Any other questions or comments? Back there? Is that Meyer Shoshone? Long time, Meyer. At ConEdison still?

MR. SHOSHON: Yes. Is this on?

MR. CAULEY: Why don't you come up to the front one?

MR. SHOSHON: (Inaudible.) The panel has made a lot of insightful comments on how to contain (inaudible) in the long and short time frame but there are a couple of things that I'd like to mention that (inaudible). I just want to underline that every coordinate that we move forward that moves (inaudible).

MR. CAULEY: I think Tim Bush in the back? Why don't you state who you're with, Tim, for the recorder?

MR. BUSH: Tim Bush (inaudible) Consulting.

We spent a fair amount of time this morning talking about state estimators and real time monitoring and the comments I'd like to make first of all and I hope we're not giving short shrift to the value of scan data in real time monitoring alarming on that scan data.

The state estimators run every five minutes or so. Real time data comes in every three seconds or ever five seconds, whatever. It's also possible and Mike could speak to this new contingency analysis that scan rates for thermal -- we can't do it for voltage -- and there's great value in having that information and having an alarm quickly.

The impression I get is we're leaning more and more toward putting all our eggs in the basket of state estimation and it certainly is a valuable, a wonderful tool.

However, it depends on having an accurate network model and what I would like the panel to speak to is what suggestions would you have for ensuring that each state estimator throughout the interconnection knows the status of the transmission system -- as lines go in and out of service it is critical that those state estimators have that information and what the results are going to be (inaudible) so I would like to get some thought how we make sure that everybody knows and everybody knows quickly as to what the transmission status is, what electronic (inaudible) in the network and what we can do to accomplish those negative entropics.

MR. CAULEY: That's a really good question for panel C but we're going to let the panel A guys take a stab at it too.

MR. KORMOS: I'll take a quick shot. First off I want to reiterate what Tim said. It sort of blew over my slides on tools but I absolutely agree that the scan data contingency analysis distribution factors are critical and you can't come up with voltage surge gates as well for distribution type analysis. That was part of my discussion, you're absolutely right. State estimators are not infallible they do fail, the can fail, bad data does cause them difficulty even though ours is 99.99 percent or something like that -- we still heavily rely on our scan data and I did sort of blow over that kind of redundance and overlap. I wanted to work on my presentation and so I just wanted to support that.

As far as the network model it is a difficult question and I think particularly with MISO and with what our joint operating agreement now states, we've tried to really tackle that, really tried to come up with how basically we are exchanging full network models with each other now.

But we still need to then decide how much of that model do we need to put into each other, how much of the data and how often the data needs to be transferred -- that is the real challenge right now that we're working with and I think Mike pointed out one of the things the reliability coordinators very quickly need to do is sit down and figure out what those critical facilities are right now and get those in place and get the communications, the data, we have ICCP links in with everybody at this point. There's no reason we can't be transferring this data which is just a matter of getting down, assimilating that and putting a process in place and that's a lot of what our joint operating agreement is with MISO is to put the process in going forward, it's not just enough to do it one time. The world will continue to move and evolve and we're putting in higher level executive steering committees as well as working groups to then further that effort.

MR. CAULEY: Okay Scott, I think you were next -- Scott Moore?

MR. MOORE: (Inaudible) I heard comments from the last week or so and my understanding is that FERC has raised an issue about the cost of RTOs that (inaudible) transfer RTOs (inaudible) is that cost (inaudible) borne by transmission operators with some working towards this transfer of RTOs but then we should stop in order to reduce the cost to the ultimate customer.

My concern is that if we just cut today, if we need some redundancy in the margin in the system, that you have to have that fail safe with the transmission operator is looking at the (inaudible) as well as for the reliability coordinator that has a part in RTO is more training on a wide area system because you have to have that expertise in that dual output area to help work through and supplement work being done by (inaudible) feeds.

Also (inaudible) RTOs are generally looking at the voltage system and we know that 130 and 230 and 345 still could be looked at at the local level. Part of my concern is the comment that FERC's expectations that some of these redundancies are transfers of responsibilities from the POs to the RTOs would require the operators, the transmission operators, to quit doing those in order to reduce the cost.

I want to make sure there is recognition (inaudible) that there is some understanding from an (inaudible) standpoint that there is a need for redundancy in modern transmission systems and that in order to make sure a local generator problem doesn't go widespread is that you do monitor the load bearing (inaudible) in a wide area and that some of these call for a limited (inaudible) are necessary in order for (inaudible).

MR. CAULEY: Okay. Next?

MR. ALLEN: Hello, I'm Eric Allen from the New York ISO. The comment I have relates to reliability coordination and it's (inaudible). I'd like to comment on the major role that software failure played on August 14 as pointed out in the Report and particularly relates to the statement that the developmental software was not considered assured as being used as a secured power system.

Most everybody that I've talked with is familiar with the extent of experience that using software has been with bugs and I'd like to see technology lags that do (inaudible) and clearly "why is software so bad?"

August 14 illustrates the potential consequences that poor software quality can have. And the latest (inaudible) any software that's used in power system operation should be very rigorously and thoroughly tested.

For example, every line (inaudible) area which is being covered by the software monitor should be tested and I think those comments made about using new software systems, I think that it is more important to use proven technologies as opposed to using new systems. Thank you.

MR. CAULEY: Okay, Margie? Margie Phillips I know used to be at PICO but I don't know where you're at now.

MS. PHILLIPS: (Inaudible.) I just wanted to make three observations. One is, I think that all the engineering in the world can not help you get over a real problem you have which is that load shedding is a tool to be used but is a politically unacceptable tool. And somehow it seems to be that that is going to be something that happens to (inaudible) and it also goes to coordination to a system when you have to pull the trigger, it will have economic consequences. So I recommend that you tell me (inaudible).

My second one is when we talk about August 14 responsibilities we have to talk about DOE. And that's a topic and I don't know where the Republicans are showing any penalties (inaudible) when we talk about homeland security responsibilities -- there are some consequences to failure to step up to the responsibilities. You have not essentially done what you have set out to do.

And my third one (inaudible) Mark, I'd like to take a pot shot at you. I think that in a world of diverting utilities you still have blackouts. I would argue that it is a real shame for our market that we have had a slowdown at (inaudible). Those of you who are in PJM New

York and New England who do have the power to (inaudible) these systems, you know that -- the system operator has more information over a wider area than anybody else. That includes generation and information problems (inaudible) and in addition I would like to FRCC where the information is shared among transmission owners (inaudible) PJM all market participants see and want this information we could help to distribute to alleviate the things that we see that are going wrong and frankly it is the degree that we are getting to a structured market according to PJM (inaudible) is where we want to go and in fact that was what was lacking in MISO is that it had none of the information that other existing Northeast RTOs had. Thanks.

MR. CAULEY: Never was bashful. Jack?

PARTICIPANT: My name is Jack (Inaudible) and I'm from Dominion. And the points I want to make are related to real time operations for reliability tools, real time models and best practices. I think standards need to be put in place that define detailed to (inaudible) criteria for real time models particularly in terms of the size of the models required and the fidelity of the models and the upkeep of the models. We also need standards to define criteria for proper level of observability of the facility that's being modeled. We need standards to define acceptable levels of performance and solution quality for the tools used in the models in particular status and real time contingency analysis.

I think the best way to arrive at those standards is to do a multi (inaudible) wide assessment of best practices and I think to do that we need to establish another working group within NERC with a power system engineering perspective not a perspective of managers directed by vice presidents -- that is, the working of the people involved in this should do the survey analyses of best practices and come up with recommended standards --

MR. CAULEY: We'll take one or two more questions and then I want to keep us on schedule with, and there will be an opportunity to ask questions and make comments after each panel but I do want to keep things going smooth.

We'll take the last one there and then let's see, we'll take these two here and then we'll take a break.

MR. GILBERT: My name is Vince Gilbert. I'm from the Nuclear Power Industry. But I don't know where the switch is.

MR. CAULEY: Just come up to the front one.

MR. GILBERT: My name is Vince Gilbert. I'm from the Nuclear Energy Institute and I represent the nuclear power industry. The (inaudible) safety is analogous to your electric reliability and I think there are a number of comparisons we can make that will give assistance to you.

Our standard nuclear performance model relates to the NERC function of how we conduct and systematically identify and ensure good practices and performance matrices and how we conduct evaluations with (inaudible) standards -- how we develop simulator training and accredit our training programs, how we involve suppliers to reduce product development costs, how we conduct emergency planning, and exercise the value that we see in developing industry consensus (inaudible) with our regulator the Nuclear Regulatory Commission and in part finally say that the nuclear industry has formed a task force which is responsive to the (inaudible) and need to distinguish --

MR. CAULEY: Thank you. And one last comment and then we'll take a break.

MR. MURPHY: My name is Paul Murphy. I'm with the (inaudible) market (inaudible) operator in Ontario. At separate times virtually all the panel members commented on the need for good operator training (inaudible) demonstrated the same thing but I would just like to emphasize one point made by Mike Kormos with respect to the inquisitive operator, eh?

I know in my own experience there are many times when blackouts have been avoided or serious consequences have been avoided not just because we had good tools monitoring things or just because we had good procedures in place but because our operators are constantly assessing what they were exposed to asking questions that needed to be asked gathering information that we needed to gather and making connections (inaudible) some unusual circumstances that are not necessarily obvious as to the normal process observing and I just want to make clear that I would even extend the need for some implicit cultural thing beyond just operators where they follow operational planning or as when management (inaudible) it's a very difficult thing to get at in terms of measuring data when you focus not only to make these things happen but this is very much more of a goaler cultural thing -- very much related to management of the organizations involved in (inaudible) organizations and these are the types of questions that need to be continually asked.

The second point I want to make is with respect to standards and (inaudible) which is what really demonstrates (inaudible) it may be appropriate to have more stringent standards (inaudible) and the varied reasons for that. That's why it was demonstrated very clearly that blackouts don't respect regional boundaries any more than they respect international boundaries and the fact that 50 million people can be affected by this sort of event demonstrates more clearly than anything else that these must be very high standards in our history throughout the industry internationally.

MR. CAULEY: Okay, thank you. These are all very good comments and keep your comments coming. We'll have four more opportunities to do that.

We're going to take what is now a 13.5 minute break until 10:15 a.m. and we will reconvene panel B.

Could I make sure I get all the speakers? Panel B and C because I'm going to try to get both panels in before lunch so I need Kim Warren, Vicky, I don't know if you have slides. Zwirgel I have. I need Pat Doren, Steve Lee and Victoria.

(A brief recess was held.)

(Back on the record.)

MR. WARREN: (Blank tape gap.)

This is by far the best approach in dealing with emergencies. This is accomplished through good planning and coordinated operations, adequate investments, effective certification and compliance audits and reviews. Mandatory enforceable standards set the requirements but they establish the minimum requirements.

Compliance with those standards requires functions to be assumed by entities equipped with the required attributes, authorities and capabilities. All entities should comply with approved reliability requirements that are critical to the prevention of wide area outages.

Prevention hinges on being prepared. All parties must be ready for the next contingency. Prevention -- preparedness hinges on training, comprehensive knowledge of your systems, your service area, your facilities, your operating companies along with continuous rigorous education by all. Conditions change often in unanticipated ways. All entities must be capable of ensuring their systems remain secure immediately following any significant change in status. Clear accountabilities are essential for the day to day integrity of grid operations.

With respect to improvements in emergency response, we need to establish a framework for a coordinated and effective response to emergencies. A good framework assigns each market participant specific roles in an emergency plan. This coordinated effort assures the capability to respond to a wide range of emergencies.

Operations staff require operating guides and strategies that are robust and sufficiently wide in scope so that they may apply to a wide range of post disturbance configurations.

Continuous review and update of restoration plans and procedures must be carried out. Various components of the plan should be subjected to integrated testing so that equipment critical to the restoration process is available when called upon to act and performs as expected.

Effective emergency response requires capable and trained personnel implementing actions supported by the right processes, facilities and equipment. Pre-identification of priority loads is critical for an orderly restoration.

High standards for an uninterruptable power supply requirements for equipment such as SKADA systems and phones is essential. NERC certification is a minimum requirement. Operators require an in-depth detailed knowledge of their area and sound general knowledge of surrounding areas.

As for drills and exercises, regular extensive emergency preparedness base training is essential. Clear, concise, controlled, orderly and methodical restoration implementation helps prevent equipment damage, the environment, protects the public, and ensures orderly load restoration without recollapse.

Staff need to expect the unexpected. During contingency events problems or barriers will occur. These cannot be allowed to distract staff from their obligations and priorities. To manage system emergencies effectively during precontingency phase operators must operate the system under studied and known conditions at all times. The ability to derive limits and act within NERC approved title lines is a key objective of emergency preparedness.

Tools must quickly enable operators to identify the next critical contingency and assist in determining actions required to remain secure. Multiple contingencies occur regularly and cannot become a source of insecure operation because of inadequate training tools or procedures.

Of course, proper communication protocols must be followed at all times.

With respect to authorities, the IMO is the RC, the control area operator and also directs the operation of the IMO controlled grid, which encompasses equipment 50 kV or greater. Within the Electricity Act, the Ontario market rules downstream agreements and manuals, individual entities have the right to declare emergency conditions for safety equipment and environmental protection.

The IMO has the local and global perspective and has the authority, responsibility and obligation for determining emergent conditions. We found this practice to work exceptionally well.

Regardless of the makeup there needs to be clear delineation in many areas. We firmly believe that NRC should have the authority to declare emergencies within their reliability area.

With respect to empowerment to prevent cascading outages, to assist in this reinforcement specific stronger language should be added to current NERC policies. As well, specific directions should be sent to reliability coordinators and their operating authorities to reaffirm their obligation to the interconnections.

As for the availability of timely corrective actions, we believe system resources are available for response. The important factor is the reliability coordinators being aware in detail of the full range of options available to them including load shedding.

To illustrate that load shedding is an effective emergency action, due to extreme events, Ontario has shed firm load to remain within security limits and protect the interconnections.

We take the view that over reliance on transmission loading relief as a method to manage real time limit violations is not prudent and can in fact lead to an insecure operating state.

To illustrate this inadequacy, there have been two instances in the last six years where portions of Ontario have collapsed when external entities attempted to call TLRs while overloads existed in their systems beyond the NERC 30 minute standard.

On the question whether a full range of credible contingencies is being assessed we stress that, in addition to the exhaustive range of analysis, appropriate actions must follow from the results. The most critical is read preparation. It must be as soon as possible but no longer than 30 minutes.

It is an obligation that rests with all the RCs to act in the best interest of the interconnections at all times. Satisfying total reserve requirements is not enough. Reserves must be located appropriately to ensure associative operating security limits can be met during activation.

As for improving communications, priority communication (inaudible) are extremely useful. They also need to be used by staff with the authority to act. Consistent industry approved terminology and positive confirmation helps prevent errors. Practice and training is important but these points need to be included in everyday processes in order for staff to be successful during contingency events.

To maintain proper focus during contingency events, we found that if rules and authorities are well established and documented and overall expectations and priorities are well understood by all parties, then restoration incidents go much smoother with overall objectives being met in a timely way with minimal adverse effects.

Thank you.

MR. CAULEY: Okay thank you Kim and the second speaker is Vicky Van Zandt of the Bonneville Power Administration and also a team leader on the technical investigation in the area of operations.

MS. VAN ZANDT: Thank you. Loud enough? Okay.

So the items that I'm going to speak to have come out of the operations team largely and that's kind of confirming because you will have heard a lot of these things from Tim's comments and from the previous panel so we must be zeroing in on the things that we need to do.

So question one, four items, assessment is necessary and it needs to encompass more than seasonal studies of typical conditions, more widespread determination of simultaneous transfer limits taking into account generating patterns, reactive requirements and voltage collapse points. That's done in some places and not in all places.

The second item, interactive simulation of load probability but severe system conditions to recognize disturbance characteristics and to practice response techniques for both disturbance response and restoration.

So a lot of the entities involved in the disturbance footprint had simulators but had not used them in some time.

The third item, good visualization tools to help with this recognition of disturbance characteristics and to get immediate feedback on the effectiveness of operator actions in real time without the power system effects taking place but just assimilation of such.

And the fourth item, reinforcement of training curriculum and testing to include simulators using actual as well as potential disturbance scenarios, recognition of disturbance precursors, mitigation of disturbance severity -- include lessons from other areas and regions.

I think Dave's presentation earlier as we got started, there were a lot of common themes in some of the big disturbances that this continent has undergone and hopefully we can eliminate having to learn them over again -- common causes in disturbance because we've effectively transferred the learnings from one area to the next.

On the second question related to tools, oops -- a few items here as well and the next panel will speak to tools as well. So I have four items here too. The status in alarm features. We need to develop a minimum fail safe criterion for EMS systems to include back up provisions, functional monitoring and assessment and transfer of control to other authorities should the primary and back up systems fail.

Perhaps the consideration of 24 x 7 IT system monitoring of the EMS tools that's utilized in some places and not in others, and this would be separate from the system operations staff.

Second, thermal voltage collapse studies both either real time or off line or on line -- I'm sorry, had it right the first time -- real time or off line but, in any case, with current system conditions.

Third, if cascading occurs for some contingencies more quickly than an operator can reasonably respond, 30 minutes seems to be the break point, it has to have automatic controls in place to act as a safety net. So we'll hear some more about that in the system protection and control panel.

Fourth is just a note -- sort of an epiphany from me as the investigation is going forward -- is all the studies in the world and the assessment and the contingency planning, all of that, is regardless of the care taken in doing that with good rigor and determining what the current status and what you think the vulnerabilities of the power system are, they don't mean anything if they are obstacles in the transmission rights of way particularly in the summertime.

Transmission lines that trip out before overload pretty much render that assessment invalid.

Okay, the third question -- I have six items here. Between system items and reliability coordinators, who has authority and responsibility to do what? It's pretty much the feeling of the group that control area operators are the first line of reliability defense and should be the first to declare an emergency if the tools in their assessment and their visibility is working well, should be the entity to take action.

Control areas need to raise the alarm when they're in trouble so maybe some communication protocol or something other than just dialing the phone, maybe a red button that opens communication lines so a reliability coordinator might be hearing what's going on in the control center would be a possible consideration.

A third item, if they don't either see that there is an emergency or fail to raise the alarm, reliability coordinators have to have sufficient authority and means to carry out actions to preserve reliability and that needs to be confirmed with regular and rigorous audits.

Fourth, if the RC sees a disturbance in the making, they need the authority to declare an emergency and order specific relief and conversely system operators need to comply -- if they disagree, comply first then argue about it later.

Fifth, the reliability coordinator needs enough visibility with enough granularity to assess system problems and determine appropriate responses to shortstop a potential cascading problem.

If it's at too high a level or too aggregate a level then their ability to render aid if the primary line of defense doesn't work is limited.

Last for this question, the reliability coordinator needs tools sufficient to determine simultaneous limitations on transmission paths. That's done in some places and not in others. And it needs to include thermal, voltage and transience stability if that's appropriate.

In some areas state estimation and contingency analysis is necessary but it's not sufficient. If a contingency analysis says you have a problem, you do. If it says you don't have a problem you still might. It does not provide transience stability limitations.

The fourth question, two items -- the authority to take actions and responsibility to take those actions to prevent a cascading outage. Industry really needs to support operators exercising that authority. It is clear in the NERC policies and in operating procedures, standing orders and control centers that operators have that authority and they have that responsibility but their job, day in and day out, is to keep the lights on, so we need to reinforce that. And there have been some instances where operators have not been congratulated for shedding loads to prevent a disturbance because if the disturbance is prevented somebody's load was lost and the "bad" thing didn't happen, so there's a lot of second-guessing.

Operators need to have and know where their collapse points are voltage wise. Assessment tools need to include wide area view of current conditions and warning of contingency problems beyond that of simultaneous thermal limits of transmission circuits.

The fifth question really reflects what Kim's comments were -- are there adequate resources available to respond? Not always. TLR-6 is load shedding. It must be possible to shed load very quickly if you're going to use that tool, if you've already got an overloaded transmission system then cutting schedules is not going to perhaps be in time. It will likely not be in time.

Second item, we need a redispatch stack of options to relieve transmission quickly if there are resources on either side of a loaded path or a path in trouble. Schedule reductions are meant for contingency relief proactively and in anticipation of a possible contingency. They are not for emergency action, so we need to beef up those tools in some instances.

The sixth question, three items, standard protocols and terminology -- in reviewing a lot of the transcripts there were some time used in getting to the point, if you will -- so standard protocols, getting right to the point and using common terms, would be helpful.

Second item, emergency drills, simulation with both the control area or transmission operators and the reliability coordinator in play -- would be good.

The third item, it's necessary to see into each others' systems far enough to be effective. Agreement at the scenes about what facilities would be discussed about relevant control area operators and reliability coordinators, which ones matter -- needs to go far enough into the overlapping control areas and footprints so that those facilities would have an impact on their neighbor, they need to be included and discussed.

And the last question, recommendations to ensure operators' focus on reliability -- three items. Dedicated personnel assessing the status of the system, possibly leading the commercial arrangements separate from operation.

The second item, communicate with each other within and between control centers with some evidence of time trying to assess a problem before you raise the alarm to the neighboring control area, their own reliability coordinator or neighboring ones.

Finally, the last item, protocols prioritizing the attention of at least one control center dispatcher to determine the course of action if you're in a disturbance and it's progressing. And delegate commercial schedules, hourly commercial schedules or routine phone calls, to others.

So I will stop there and look forward to questions.

MR. CAULEY: Okay thank you and we'll start with our again our distinguished panel of investigators. Do you have any questions or comments?

MR. MEYER: I'd like to ask the panel and the audience also about best practices with respect to training particularly with respect to identification of emergencies and responding to emergency conditions and I am interested in the possibility of, I recognize that the training of this kind can be a burden for some companies and that might cause them to question do they have a way to really meet some of the standards, the high standards of performance, that might be seen elsewhere.

But I think some of those problems could be overcome through the establishment of more centralized training programs and facilities that would be widely used by companies or organizations across broader areas.

I realize you would have to fine tune some of these training programs to meet regional conditions and regional needs, but I think that's a problem that could be dealt with.

So I welcome some feedback on those themes.

MR. CAULEY: Okay anything from the audience?

MR. HILT: Gerry I have a couple of questions.

MR. CAULEY: All right Dave sorry. I didn't see your hand go up there.

MR. HILT: That's all right. I wasn't fast enough at grabbing the mike. That's quite all right.

From the panelist as well as the audience, one of the things that was mentioned here was load shedding is a tool and has to be a tool that's available to the operator to preserve the system. However it appears to be politically unacceptable and we are not doing an adequate job of I guess congratulating or I guess promoting "the right thing" being done by the operators.

I would be interested in hearing what you think we can do about that in terms of changing that political perception that there comes a time to preserve the system that we need to shed load. What types of recommendations we might hear from that would be something of interest to me at least as to how we, not necessarily promote load shedding but promote it as there is time to do it and has to be done to preserve the system, otherwise putting it at a very large risk as it was on August 14.

The second thing I heard was talk about location of reserves and I know we're going to get into that a little more in the planning and design but I'd certainly be interested in hearing some comments on that and concepts of the redispatch stack, certainly that may have some impacts on the development of wide area transfer limits and simultaneous transfer limits if there's a requirement for a certain amount of reserves to be provided in a given area.

And that certainly may be necessary but I would be interested in any comments or recommendations on those areas.

MR. CAULEY: Okay from the floor here. Let's see, Ray in the back and then we'll come back toward the front here.

MR. KIRCHOW: Ray Kirchow from DTE Energy -- does that work?

MR. CAULEY: Not any more, no.

MR. KIRCHOW: I'm with International Transmission Company which are the old assets of Detroit Edison and the question is related to something that Dave was saying, are you considering changes to Policy 9 in terms of the emergency procedures part of it such as load shedding to maybe ease the operators' burden on calling it and not being condemned for doing it? I would recommend something like that.

I mean, that's one way of handling it, putting it right in Policy 9, and actually Policy 9 itself giving it a little more teeth -- you know, there's a lot of criticism of

TLR procedure being slow -- well, there's probably ways to jazz it up a little bit. I'm not quite sure, I don't have any specific recommendations right now but there's a lot of complaints about it and I think one of the first things that could happen that we'd like to see is the tool that implements it, the IDC be improved, make it more of a real time, speedy tool, I'll call it.

For example, the SBX was not updated on August 14 so it would be nice to have that to kind of force people to input topology changes on a real time basis and the other thing would be to actually input dispatches into the IDC.

When you do this, right now, the IDC mimics dispatches but if you actually input the real time dispatch wouldn't have to mimic it any more. It could calculate relief from the real time system.

This is not going to be free and right now NERC budget pays for this so somehow I think there should be an incentive to make that a little bit better.

MR. CAULEY: Okay Scott?

MR. MOORE: Scott Moore, AEP. I have two responses to both Dave Meyer and Dave Hilt. The first one I'd like to address is the training issue. We work rotating shifts with our system operators and our reliability coordinators and quite often, and actually I see a dichotomy between the non profit organizations who basically can pass on all their cost to the members, do an extremely good job of making sure that they have adequate numbers of shifts to allow for adequate training.

As I look across the industry and at AEP as well where we're not non profit organizations, we don't have the ability to pass on costs to our members, that we take a hard look at the number of operators that we have and, over the course of the last 10 - 15 years, I have noticed within the industry and talking to people, that we have down sized quite a bit of our operations staff. We've done that at the same time that our staff has gotten older and maybe available for more vacation time.

And quite often, when we staff up our shifts on what we call a "relief week," that relief week is designed to allow for training and to relieve brother operators who are on vacation who are gone, who have gone to training or are sick.

And unfortunately when you look at the way that a lot of shifts are now designed, and you have to cover the basis of everyone on relief, that there's not a whole lot of time left for training.

So there's two pieces. One is the amount of time for training and the second is the type of training that you're training on, that Mr. Meyer addressed.

So those are the two issues and I think that NERC needs to look at and the personnel committee of NERC need to look at what are the minimum amount of training days required for certification? We have, as we go forward with continuing education program or testing program, it's really not defined although we're looking at a certain number of hours, and I'm not sure that's really going to meet what's really needed. It may meet what's needed for certification but it's not what's needed to have a good, properly trained operator.

And I think if you look at other industries, if you look at the nuclear industry, there is a minimum requirement of training dates and I think that NERC needs to look at that in terms of our system operators, those who are dealing with the reliability function.

So it's both the amount of training you get and what you get trained in, both locally and from a wide area basis in emergency operations.

The other thing I would like to address is the load shedding issue and I've mentioned this to others and I've talked to Vicky -- operators, their frame of mind and what they're trained to do, is keep the lights on.

Now one of the tools in order to keep the lights on is to turn them off.

But they're reluctant to do that -- and it's not only just politically reluctant for managers to do it or for regions to do it, and who's going to pay for it -- but the operator sitting at the desk is even reluctant because he's been trained to keep the lights on.

So what we need to look at and what we have in place already is under-frequency load shedding. You know, that last ditch effort to keep the system there. But what we don't have is under voltage load shedding where our special protection schemes that is looking at the critical flow gates that, if you do get the contingency loading, that you could have a special protection scheme that, if the proper thing to do is to shed load regardless of voltage, regardless of frequency, but if the loading on a particular flow gate gets to a point and normally this happens fast because of a contingency, that you have special protection schemes to remove the load and preserve the system.

Now I think this would be a backstop -- but the operator still has to be trained to take proper action as you are looking forward. But if he doesn't or if he's unable to because of the time to take that action, then you need to have better use of special protection schemes that are automatic and that are armed and are you know under voltage relaying that can take care of that.

So I think those two issues need to be looked at very carefully and critically.

MR. CAULEY: Okay. I'm assuming you guys are okay unless I hear from you -- okay, go ahead.

MR. WARREN: I was just curious if you wanted us to respond.

MR. CAULEY: Just give me a wave any time.

MR. WARREN: Just a wave. Let me know if I jump around a little too much.

But on the issue of training, there was a phrase of "being a burden" -- but that's actually an investment that we take quite seriously and I think in the Northeast the time spent on training for the RCs is in the neighborhood of 15 to 20 percent of their time and we have dedicated trainers. We have regional restoration training drills, we have in-house training drills but they're all market participants and such and we find them quite effective. And there's some use of simulators.

But what we've found actually is even more beneficial lately in emergency preparedness training drills, we use our normal operational center for the actual drills themselves and we operate the systems and such, from the back up centers during that time and we go top to bottom with our training and exercises and such and we involve more than just the operational staff, the people that have to support them, we found that to be very, very beneficial, obviously during August 14 and 15.

As far as load shedding, I'm disappointed that we have to promote it as an operational tool. It's already in Policy 9. It's the jobs of those that supervise the operation staff to ensure they're properly prepared. It's unfortunate that people look at it with some negative connotations but it is a very effective tool to relieve an operating limit violation.

And as far as the locations of reserve issues go, throughout the Northeast we have some very detailed policies and basically when we tackle any given day, we've already been well prepared through our next day security analysis and such in the information exchange with our neighbors about what elements are out of service and we look at the removal of all elements to ensure that other than connected load we can move reserves around to satisfy any expected contingencies. And that's -- we term that more "area reserve" than just system reserve.

We're not only looking at just megawatt transfers but also reactive in such in being able to react timely to any contingency event.

So then when we drill down frankly through area reserve and the term called "repreparation" -- that's an operating doctrine, if you will, that instills in the operator's mind that it is not appropriate to sit over an operating security limit violation and his actions to relieve that constraint should be as soon as possible. He doesn't have the luxury of time normally in his favor.

That's it.

MR. CAULEY: Vicky?

MS. VAN ZANDT: Gerry? On best practices, I think there's probably not anything better than simulation of a disturbance you've lived through. That would certainly have the operators' attention especially if the disturbance had a bad effect.

Out in the West we have simulated the August 10, 1996, outage, what operator actions could have prevented how that eventually came apart. So simulation is kind of hard to put together especially if it's interactive and includes operator actions, we have to anticipate that and in a wide variety of those in order to do it but I don't think there's a substitute for it.

It's also possible to use other simulators. You'd certainly probably want to practice on scenarios that were in your operating area but other disturbances as well.

We've gone to hours out to for folks who wanted to train on actual events or potential disturbances so perhaps if entities didn't want to develop their own, there are others that can be used.

Load shedding reinforcement -- I have operational responsibility for a pretty good size grid. We have two control centers and they can fully back each other up. I recently, since the interim report was out, went to visit each of the control centers and did a presentation about the facts and issues of the August 14 scenario.

There was -- I've never had quite that level of attention from the system dispatchers before. And we've revised our dispatcher standing orders to include -- you not only have the authority if, in your judgment, you need to shed load in order to preserve the system, I want you to do it and I will stand right next to you when the inevitable second-guessing occurs.

So I think reinforcement of that, well, unfortunate and I agree with Scott that it's counter to what system dispatchers are trying to do -- they keep the lights on so they hate to turn even a single one off. But sometimes it's necessary.

And then finally I also agree with Scott in having some safety nets that are automatic. A wider use of under voltage load shedding.

MR. CAULEY: Okay. I think you, the gentleman over here, you were next?

MR. DELAY: My name's Frank Delay. I'm retired. In my youth I worked for ConEdison and I'm old enough to have remembered the post analysis of the 1965 blackout and the 1977 blackout, the '77 blackout I was senior enough that I had a fair amount of responsibility in conducting the analysis of it.

The first thing that strikes me in listening to this panel and the prior panel is how many issues overlap. The same issues -- '65, '77, and I looked at a number of blackouts subsequent to that -- same issues.

A point I think has to be addressed in the longer strategic terms is the fact that what you tend to lose is what I call "institutional memory." At the time of the 1977 ConEd blackout people were running around trying to remember what we agreed to do in 1965. If I look back now at the people who were in management positions in 1977 at ConEd, we're all retired if not gone even further beyond that.

(Laughter.)

MR. DELAY: I think one of the things you have to do is put together some sort of a "lessons learned list" and it's not a short list. It is a long list. In sitting here today I said, "What do I want to comment on?"

I probably would have been up to about 100 things but I think you have to put these lists together.

Now trying to respond to the issues by writing more standards is nice but I think you have to recognize there's another issue and that's the quality of the response to the standards. You can say "we'll have metering."

But then you can look into a whole spectrum of how good is the metering? Provide more data to the operators? The operators are human beings and can only assimilate so much. How do you deal with that?

I think you have to have some measure of good design, good practice -- we've heard the gentleman refer to "a good practice installing computer programs." Well, I think that applies to almost everything you're going to do. It maybe is cross fertilization, one company versus another, but I think you have to have something in place for that.

A third thing I think has to be addressed, and what I've noticed in the past in post-mortems on blackouts, they tend to involve planners and operators. But I never, hardly ever, hear design engineers get involved and I know when we looked at the ConEd blackout we really dug into some of the engineering issues.

There was an example I use on restoration. One of the problems we had was trying to restore quickly was we wanted to change transformer path on distribution transformers.

Well, it turned out that the pack changing mechanism was located from a voltage source in the low side of the transformers so you'd actually have to energize the transformer to get the low site energized before you can do the pack changer.

A simple, dumb thing but it impacted restoration and the problem with the design engineer that had never been sensitized to the criticality of the restoration issue.

Now separately, a theme that I've heard run through a number of people today was the availability of resources. Again it's very nice to say you want to do things but I think you have to explicitly consider the availability of the personnel to do them and the financial resources to them.

I don't know but I suspect that, given the financial crunches that had gone on in the industry over the last few years, it is very, very easy to cut back on training, right of way maintenance, and you can go on and make a laundry list of things, and this is sort of like "well we don't talk about it because my boss won't give me the money" but I think it's critical that these financing issues and personnel issues be addressed.

Now finally on more technical issues, in reading the report, one major thing that struck me was the "omittance," if you would, of any discussion of restoration.

And by any definition that we look at when we talk about the severity of a blackout it's duration is part of that equation. The number of people involved is part of it, but duration is part of it.

Look at your distribution indicia, the ones that are used by distribution planning duration. I urge that a thorough review of the restoration process be undertaken, again, to learn lessons -- how can it be made quicker? I'll leave it at that.

MR. MEYERS: Gerry, let me respond to this, the question about restoration.

In writing the Interim Report, we looked very closely at our mandate from the Task Force, which was the mandate to the task force, which was to identify the causes of the August 14 blackout and devise recommendations.

It did not mention restoration in our view.

That does not mean restoration isn't an important issue. We think it is a very important issue and we are going to conduct an independent parallel analysis and we will report on that in due course.

MR. CAULEY: Right behind Scott there?

MR. THOMPSON: I'm Bill Thompson from Dominion.

I'd like to make a comment about load shedding and I agree with everything that's been said but I want to try to take it one step further because I think we all agree that the reliability coordinator has to have the authority to order a load shed. I don't hear a lot of disagreement with that.

But if that order is given to a bunch of control areas who don't have the capability to automatically go into their SKADA system and shed load it's probably a worthless command.

And I think one thing we need in the industry is a standard that NERC puts out that we all, as transmission owners, I guess, or distribution companies -- I'm not sure where that responsibility lies yet.

But let's have a standard that says "you're going to have this capability to shed load automatically if it's ordered by the reliability coordinator. That's one thing that I strongly think that we need as an industry.

I would be willing to participate in that and at Dominion we have a very good load shed program. I hope I never have to use it again. I used in in 1994 along with PJM, my friend over here Mike Kormos and his staff, and some comments were made about the political aspects of shed load and I have to agree with all that. That's certainly the last resort that any operator wants to use.

But let's face it, that is better than the blackout that could happen if we don't use that resource.

MR. CAULEY: Thanks, Bill.

Way in the back, is that Meyer again? Yes.

MR. SASSON: Thank you Gerry.

As I'm hearing the comments about load shedding I thought I would add my comments on the same issue. And I think the hierarchical, the way I would like to look at it, and the way we look at it in New York, is that first of all we do have mandatory rules. Those rules have developed over many, many years of experience. Some came out of orders from our public service commission out of the '77 blackout for example that, in regards to having means to shed load -- but the important thing is that those mandatory rules have to be translated into procedures, operating procedures and the operating procedures, as we have all said, have to reduce to operator training so they become totally knowledgeable about operating procedures.

Operating procedures not only impact transmission owners but also as it was at the New York power pool and now is at the New York ISO -- so when you put all that together, none of the issues that we have been hearing really come to play in New York.

If the New York ISO orders the ConEdison operator to shed some load, the ConEd operator will shed load -- he'll discuss it later but will shed load now.

If there is a rule saying a line loading cannot exceed a certain emergency level for more than five minutes and if the operator cannot through all the normal things that he can do in five minutes, get below that level, the operator must shed load to get below that level because that's how you're going to protect the system. You might lose a little portion but you're protecting the larger portion.

So those are rules and procedures and should not be that the operator makes a judgment at that point he has five minutes -- five minutes are up -- he needs to shed load if the loading is still above that very high emergency level.

So mandatory rules translated into procedures translated into clear authority, hierarchical authority -- and I know I'm repeating what panelists have said -- but that works and that's what we have in New York.

Thank you. I thought I'd mention it.

MR. CAULEY: Okay, thank you Meyer.

Bill Middlestadt from Bonneville Power Administration?

MR. MIDDLESTADT: Thank you.

As the system has operated closer to its limits the challenge will be greater for the operators for some of these multi contingency outages and they may still have the ability to handle the more routine outages. But the challenge will be greater for the multiple contingency outages.

I think it would be useful to do an analysis and take a look at the coverage that we have, the kind of coverage that we can expect our operators to provide and then to also understand areas where we may need to consider filling in some of the holes that are there.

And I haven't seen a holistic look at the whole protection issue of what's covered? Can we expect to be covered by the operators and what do we need to cover in other ways?

The things we can do for the operators would be to develop tools to add capabilities that would assist them and provide them more information on actions that they can take. And then secondly going beyond that, the next step would be to have tools that would not only provide guidance for them but once the operators were comfortable with them, would actually allow the tools to initiate some actions.

And then finally we have special protection schemes that are needed when the time required is so short that the operator even with the best alarms or the best information is not able to take the action -- then we have to have special protection schemes.

And then finally beyond that, safety nets.

So anyway I just encourage taking a look at it from a holistic standpoint in terms of what's reasonable for the operators to do, how we can enhance that and then what do we need to go beyond that?

MR. CAULEY: Thank you. Any responses --

(no response)

-- okay, Kim?

MR. WARNER: I just want -- I agree with many of the things that were said here.

What we've found in our area to be extremely beneficial is, when we supply operators with information we supply more than just the basics. We don't just tell them "here's the limit and stay underneath it" type of thing.

They're aware of what type of limit it is. They're aware of the studies and the information behind it and they know what the critical contingencies are.

And that's not just for all the elements in service state. They're aware of what critical components can affect that limit and what options are available to them to try to mitigate any operating concern.

And they're given enough information that they can, during the wee hours of the morning when some of the support staff and such aren't normally there, they can analyze multiple non critical elements at a service and determine a critical operating state themselves. And they can determine their own transfer limits as necessary and yes there are calls that are going out to the operating engineering staff to help revise some of these limits and some of the limits that they come up with may be conservative in nature but they will operate to those limits.

And that's quite an undertaking to try to bring staff to that level but we've found it's very effective and it also engages the operations people from both the planning side and the operations side in numerous discussions.

That is very helpful when the engineering staff is coming up with new operating parameters that the staff will have to manage.

It's also very beneficial as we get ready for seasonal type of activity like winter, the winter peaks or the summer peaks that we have. They're engaged months and months before.

And as we see things in real time we bring in the engineering staffs and such so that they too can see the relationship between one resource and limit and between different limits and how they're reacting and to make sure that the studied parameters that they are using bear a very close relationship to real time.

And we've found that those types of opportunities when exercised have been very helpful for both entities.

Thank you.

MR. CAULEY: Thank you.

Terry Mitchell? You are the last comment for this session.

MR. MITCHELL: Yes. I agree with all the comments on load --

MR. CAULEY: Terry, Terry --

PARTICIPANT: Terry (inaudible) from Excel Energy. I agree with all the comments on load shedding.

That's one of the most difficult control room decisions to make but let's not forget about the other side of the equation, too, as emergency generation redispatch. That's part of TLI level six.

Also, even though you may not find a set of incrementing and decrementing generators right available to you, decrementing a unit on the correct side of the problem area can be beneficial while you search for some unit to increment.

So let's not forget about that as a tool for the coordinators also.

But we also keep talking about shedding load and response to a problem. I want to just go back to June 25 of '98 that's one of the events that's footnoted in the report and the part of the IMO that stayed up this time we blacked out from an event in the MAP region and everybody's all accustomed to low voltage and low frequency -- that event, North Dakota went to 62 Hertz -- and shedding load is the wrong response.

So also from an operator perspective, you also have to talk about the other side of the equation, high voltage and high frequency and not have your system go down for that type of event.

MR. CAULEY: Okay, Ed Suartz, NPCC?

MR. SUARTZ: Thanks Gerry.

To pick up on the discussion, this is an emergency response panel and we have discussed a lot about shedding load.

But I'd like to take us back to how Kim started this off in that prevention is actually the best emergency response. And one of the blackouts that isn't referenced in the report is a blackout that didn't happen because Ontario took the emergency response, put itself in a super secure situation and survived the loss of an entire generating station, which our study said they could not have survived.

Their operators took the action early-early on to put the system in a more secure state.

Fundamental things we're talking about here are operating the system within its known limits. If in an unanalyzed state, we've talked about the time to respond. That time shrinks down to immediate.

We do not have the luxury of 30 minutes to get the system back into a known state. Those actions need to be taken immediately. The operator needs to be trained and needs to have the tools available up to and including load shedding to get back within known limits.

Those limits need to reflect actual capabilities. We talk about right of way clearance, right of way maintenance. The transmission limit needs to reflect the fact that right of way clearing hasn't been done in the last

14 years.

Then you're operating a system within a known state. If in fact you've got right of way that hasn't been maintained yet limits it as soon as they are, then the operator is not being given information about the system that he has in front of him.

Also in terms of utilization of PLRs in TLR three for an overloaded line is the incorrect response and we need to address that.

Just to wrap up, as an example, with an NPCC criterion, we do have a section of the criteria operation under high risk conditions. We need to consider addressing that as a NERC standard.

MR. CAULEY: Okay, thank you.

Tom? Tom Rusnor?

MR. RUSNOR: Am I on? Thanks Gerry.

There are so many great comments here that I am not sure where I am going to begin but I would just like to say a couple of things -- Scott's mention of differences between private entities, private profit making, and public -- is perfectly valid.

That is not to say that the publicly owned entities did not have any financial constraints. Over the years I have been a system planner for 25 years with accountability for taking capital projects upstairs to get approval for them for often hundreds of millions of dollars a year.

You know, I have never been refused a capital project when I presented a good, valid case for reliability. That meant doing a lot of homework, a lot of studies, often convincing senior management who didn't have a clue about what a stability analysis is -- so you've got to talk to their language and you've got to be convincing.

I'll repeat -- I've never been refused a capital project for reliability.

The other area I've never been refused a capital project in is when I could demonstrate that it was economical over the long term for a power system and skimping on a few operators is just wrong, absolutely the wrong area to skimp on.

Skimping on maintenance is also, like Vince said, is the easiest area to cut costs in. Senior management in its wisdom assigned me from transmission to look after our Ontario distribution system which at the time had something like 110,000 kilometers of line.

Whenever a request came down to cut cost by five percent, guess where it got cut? Maintenance, forestry -- that's the easy place. I had an analysis done of the forestry work and I thought they were spending too much money, about $27 million a year.

After the analysis was done it turned out that we would have to spend double that amount over a five year period just to catch up.

So was that a worthwhile thing? I think management took the easy way out saying "we need to cut five percent, okay, we'll cut five percent."

My response always to that kind of a thing was, "I don't believe it and I'm going to prove that that's the wrong action."

So you can't take the easy way out by saying "I have to do it." Management says I've got to do it. Ultimately if they insist you're going to have to do it but not without a fight. And that goes for operating, for maintenance, for staffing, for whatever the resources are, it's our responsibility to convince management where the money should actually be spent.

The other area is in load shedding and I guess I must confess I have a rather poor memory so I asked Mike Penstone in the audience to give me a list of all the places in Ontario where we had automatic load shedding installed.

And so I think Mike gave us about four pages listing the areas where we had automatic under voltage load shedding installed and I guess I was a bit chagrined because I specified a significant number of those back in the '70s and '80s.

And they're automatic. The operator arms it when he's anticipating a particular contingency but he doesn't have to take further action in most of those cases. Some of them are clearly manual and on the spot.

So you can blame the planner for putting it in place if the operator needs the excuse to arm the thing.

Those are my comments. Thank you.

MR. CAULEY: Okay we're going to take -- this is not a real break. We're going to seat panel C and we're going to get through at least the presentations of panel C before we break for lunch. That will give us some breathing room this afternoon and get us all on our merry way before too late this afternoon.

So if I could get panel C up here? I'm still missing two slides, presentations from panel C, and we will take a five minute break in place and start at 11:25 a.m. with the panel C presentations.

(A brief recess was taken.)

(Back on the record.)

MR. CAULEY: Alison Silverstein has shown up and -- do you have any remarks, Alison? Just a hello? After later? Okay.

Go ahead and grab your seats please?

Panel C is looking at tools we provide operators and reliability coordinators. Obviously alarm systems, state estimation, visibility in system, map boards, those kinds of things, were issues on August 14 and we'll hear some ideas and recommendations from the panelists on how to address some of those issues.

And if I could get somebody to chase some of the people in from outside that would be a help.

We'll go ahead and start with Dave Zwergel from the Midwest ISO.

MR. ZWERGEL: Good morning. I'm David Zwergel from the Midwest ISO and I'd just like to make a couple open or introductory comments that I would like the tone and proactive forward thinking of the panel members and participants of the improvements that we're talking about for the industry.

Just like many of you are looking at their systems, MISO is looking at ours -- in several areas and tools, training, staffing, our processes, and also in what we're calling our "reliability charter" to go back and look at, build on, a functional model and, as we start our market operations, make sure everybody knows who's responsible for what.

So we're working with our members right now, our transmission owners, on a comprehensive reliability enhancement plan along with working with FERC staff at MISO, the Department of Energy on some forward looking things, and looking to implement the best practices that others have talked about here.

We have arrangements to go and visit some of the industry experts in simulator training and we have Steve Lee from AFRE coming into our shop tomorrow to talk about some of the tools.

So I just want to congratulate everybody on the tone and what they're talking about for these tools.

But for our area I can give you an update on some of the things we're doing and what we have in place now.

First of all policy nine talks about monitoring key facilities and we were doing that and we continue to do that and I just want to note it may not be adequate although the controllers are required to monitor everything and the reliability coordinators are required to have some level of monitoring.

I'd like to discuss standards, having standards of what you need to monitor to have the proper -- so these policy decisions and clarifications must be made to determine what the reliability coordinators are truly supposed to do to ensure reliable operations.

I know that NERC operating reliability cut subcommittee is looking at that, making recommendations and clarifications to the operating committee and that will take some of the recommendations out of this workshop to help with that as well.

Observability -- the question of what is the criterion for observability? Well, clearly to have good observability, monitoring of all -- contingency analysis of all facilities of 180 and above would be required, any significant size generators and just trying to start out on a proxy for what these standards might be, say 100 megawatt and above.

Contingency analysis of all neighboring facilities that would impact the reliability would be required. I think more work needs to be done in this area as far as describing what needs to be done. Too many places in the policy there are vague words of -- "key facilities" or "adequate" -- without really describing what needs to be done.

I think that will go a long way of the criteria, what needs to be done here. The standards for this monitoring contingency analysis must be developed and implemented consistently across North America.

I agree with the comments that there are some regional differences, but there should be some strong minimum standards and we are in the process of implementing this level of observability. Our local transmission operators are required to do their job. That is still needed and as some of the other panel members have described

-- but we are going beyond what's required and we'd like to see the standards go there as well.

The next question was on map boards and back up tools. We have in place a dynamic map board today at MISO and I have a couple of views of it to show you.

But dynamic map boards are required for reliability coordinators to get the big picture. I think it is important for us to say what the "big picture" is and not just to use those words but define what we mean.

Map boards to facilitate quick analysis and decision making of the system conditions, which is essential for emergency response in rapidly changing conditions. So you could see graphically we might be getting a lot of data, SKADA data, contingency analyses, alarms, all kinds of things coming in, but it helps to get the visualization of what's going on as well.

We have implemented a dynamic map board showing all 230 kV and above facilities in our footprint. We have that in our Carmel facility. We also have map board capabilities in our St. Paul facility.

We're implementing different views from this -- Gerry, if you could just go to the next one, I could explain better.

(Slide.)

This is just one piece of it right now -- we have in the Carmel facility two ten foot by twenty foot long displays of the transmission system and it's the 230 kV and above. It has alarming capabilities as far as high and low voltages show up on it and we have indicators -- any forced outages turn dashed and you'll see blinking of the stations if it's forced outages -- maintenance outages are displayed as dash -- overloaded facilities indications and it provides a good overview to see the system.

Now the operators can click on the stations and drill down to the one line diagrams -- you can flip forward Gerry --

(Slide)

-- here's just another view of the other side of this one. I couldn't fit it on one slide but this stretches across a 25 foot display -- and you have the ability to zoom in, show more or click on a station one line diagram and bring that up.

There's also another level we're creating, it's an in-between level, a control area level, so like we could click on, say IP&L and that would bring up all their transmission facilities, 100 kV and above and show a good detail down to the station level on that so you can get a good control area view.

So there's going to be -- we have the two levels now. We have the overview and the station one line diagram view but we're implementing that middle view to help give the operators a good picture of what's going on.

And this is -- we've been working on this kind of expedited things over the last few months and it's a viable tool we have now so I'd highly recommend to those that don't have a map board to get one on your wall and keep it dynamically updated.

It's -- the scan rate on this is 30 seconds, it's updated every 30 seconds. Okay, next?

(Slide.)

Just a couple more views. This is one of the station one line diagrams -- they click on those stations and go to -- they could also pull them up on other displays whether on the wall board or at their console, they could pull these up.

And it has the megawatts, megabars, with the voltages, status of breakers and equipment and so forth.

Next?

(Slide.)

Some more visualization. We have ability to display things that, for the different control areas, look at their tie lines coming in and a summary of their system, age, frequency, you know, if you want to pull up that and look at something that's going on in the area and you want to give it a quick check, all the generators in the area and critical bus voltages -- it's another way to visualize things what's going on.

Next?

(Slide.)

Okay, more on the tools. While we have many tools available to the operator, we are putting in place a state estimator -- it's a 30,000 bus so if Mike Kormos is still here, it's 30,000 and it's -- the status of this slide right now, this slide says we will be utilizing it by end of this month.

Well, it's in place for the operators now. It's working well, solving every 90 seconds. Contingency analysis, it runs 5,500 contingencies -- it takes about 10 minutes now to get through those 5,500 contingencies.

Some of the enhancements that we're looking forward to is some parallel processing in that once a state estimator case is built and solved and passed off to different processors to run, it's put back together.

Some of the other things we're looking at is better sorting -- of the displays. Right now these displays are typically built around a control area environment, a (inaudible) of views where we need to look -- multiple areas, multiple (inaudible) areas, different ways of prioritizing and sorting those and we're working with our vendors on those enhancements.

And we do have back up tools that are flow gate monitoring tool that has over 600 contingencies that calculates post contingent flow with line outage distribution factors. Those line outage distribution factors are updated every 20 minutes based on the latest system conditions and we can update them on demand in five minutes.

That works off the SKADA data because there's discussion earlier -- you don't want to wait for the state estimator runs if the state estimator fails -- so you need to have these back up tools and run these in parallel for every critical tool to look at what your back up for this state estimator is if it doesn't solve, what are you going to have?

One of the enhancements we're looking at is, well, this runs every 20 minutes and it does take operator intervention to run a forced outage update to update these line outage distribution factors now.

We're looking at having topology processing running off a separate too, not from a state estimator result, but a separate analysis off the SKADA data to populate this so it would automatically refresh these line outage distribution factors so if you have problems with your state estimator you can go right to this other tool.

We're also looking at putting in all facilities in here like 230 kV and above is the first phase and then 100 kV - above later.

So really we want to have the -- best of both, a good state estimator running, being utilized always, but then good tools right there updated in real time for them to look at and these sort consistently to bring to the top of the page, the heaviest loaded lines, so it's -- in color code above 95 percent, the different color for above 100 percent. So it's right there at their fingertips scanned right what's going on in the system.

Next please?

(Slide.)

Okay, some more tools we're looking at and one we're calling a delta voltage tool and it's really for real time operation of some feature we're going to put into our alarming that, if we have a step change in the voltage -- right now we're alarming on high and low voltage warning levels, then emergency levels, flows -- warning levels then emergency levels, and so forth.

But we're going to add in a step change in alarm so if you see a three percent voltage change or a five percent voltage change we need to define a criterion in different voltage levels of what we're going to use, but you can automatically alert to the operators that a contingency occurred and you did have a significant voltage change.

Same thing with delta flow tool -- just another tool, another place for them to look at if there's a step change in the system and flows, they can see what lines are involved and what lines went to zero, what lines have we loaded and be able to view that and help them put the picture together.

So all these tools, the state estimator, the alarming, the flow gate monitoring tool, visualization tools -- all provide an effective means in really a back up to the state estimator contingency analysis -- if any one of them fails.

The other thing we're looking at as far as forward looking in some of the best practices is really some filtering off of the state estimator to indicate any breaker changes to put some smarts in it so instead of just seeing breaker status changes you're seeing what equipment is actually changing.

And also filtering by scheduled versus forced outage, if you have a maintenance outage going on and you know about it, you want to filter those out and make those a lower priority and rely more on the forced outages.

So we're exploring that filtering by forced versus planned right now and looking at the entire outage schedule where it has all our maintenance in with these tools to provide some good filtering.

Okay, next --

(Slide)

-- minimum tools. Yes, pardon me?

MR. CAULEY: (Inaudible.)

A couple more slides and -- yes, okay.

Minimum tools. I won't go through all of this because we've already talked about it. But the list of minimum tools that should be available to the reliability coordinator including back up for each one if one fails and instructions to know when to go to the back up tools, when to go to your back up center or when to call on other entities to monitor for you --

(Slide)

-- and I think we can just flip through that, that's the alarm screen --

(Slide)

-- back up procedures, proper notifications for these back up procedures, and really, I can just end there, Gerry. Let the others talk.

Okay, thank you.

MR. CAULEY: Okay that was Dave Zwergel from the Midwest ISO.

I have been asked by the web listeners to speak slowly and clearly when we introduce speakers so they know who's talking. It's a little more difficult to hear I think over the little pipe you have on your computer compared to being here in person.

Next speaker is Pat Duran of the IMO in Ontario.

MR. DORAN: Good morning.

From this morning's discussion I'm hearing three fairly common themes and I think they're the three key essential items in becoming a successful reliability coordinator or system operator and those three things are certification and training, authority through appropriate standards and, certainly, operating tools.

This panel is going to talk about operating tools however I think all three of those things are closely related but we will touch on all of them as we discuss tools.

Before I address the specific questions to the panel I wanted to look at three recommendations that we've made. The first that reliability coordinators must have access to a suite of tools that allow them to exercise their accountability and maintain the reliability of their coordination area.

These tools must have the capability to define and monitor interconnection reliability operating limits. They must be able to assess contingencies, must have the appropriate and reliable data to support the tools, and clear information must be presented to system operators.

Off line studies and analyses must be performed to define limits and study system conditions both pre and post contingency and finally reliability coordinators must have the training necessary to effectively utilize these tools and interpret their results.

And I think that's key in that depending on tools can really head you down the wrong path in that the operators must have the training to (a) be able to interpret the results and (b) be able to independently act if the tools are giving them a suspicious or wrong result.

First question to the panel is 'what criteria for observability of power system must be met to ensure reliable operation and avoid cascading outages?'

Operators must observe all elements that can have an impact on reliability. Identification and scope of observation is therefore dependent on the specific system and its operating criteria. NERC policy nine identifies the criteria and functions of a reliability coordinator.

In addition to what's in NERC policy nine right now, reliability coordinators must also be required to control frequency, correct ACE, perform security assessments and have monitoring programs to assess contingencies that impact on a wide area or can cause cascading outages.

And some of you might say, "some of those activities are controlled area or balancing authority functions right now" and certainly they are, but where they have an impact on the reliability of a wide area, reliability coordinators also need the authority to act.

Next slide?

(Slide.)

The second question, our dynamic map board is essential for maintaining a broad overview of system conditions. Dynamic map boards are the preferred means of providing operators with a broad overview of system conditions, modern wall boards consisting of projection screen arrays, provide flexibility in displaying key information, zooming in on specific areas, and displaying non traditional relevant information.

Our wall board and other tools are only as good as the data they depend on. It's important (1) to have sufficient data to provide adequate monitoring and (2) to have redundant data and data communication paths to reduce the risk of losing data.

Next slide?

(Slide.)

'What SKADA EMS functions are necessary to ensure reliable system operation and what should be performance criteria for each?'

The minimum required tools set for reliability coordinators is established in policy (9)(d). These include monitoring and analysis tools such as state estimators, contingency analysis tools, communications facilities and off line study and analysis tools.

This minimum set of tools should be expanded to include adequate alarms to indicate when critical functions are not updating and when data is not current. This information is critical to ensuring that tools are to be relied on when needed and are providing the proper results to system operators.

Off line analysis is critical in identifying interconnection reliability operating limits and without adequate analysis to identify limits and to provide sufficient monitoring of these limits to system operators, they cannot maintain reliability.

System operators must understand where their system is constrained, why it is constrained and what mitigating control actions they can take to look after those constraints.

Next slide please?

(Slide.)

In both real time and off line assessments contingency analysis tools are only as good as the scope they cover and the quality of data they use. The scope must cover all limits. The models must be representative of the system being studied and the data must be comprehensive and accurate.

To ensure reliability the industry must shift its focus from identifying and managing flow gates through commercial processes like TLR to identifying and managing interconnection reliability operating limits and remember that flow gates and IROLs are not always synonymous.

In Ontario we have inter connective reliability operating limits that are not modeled as flow gates because they cannot be impacted by parallel loop flows so TLR is an effective process in managing those limits.

NERC policy nine also identifies requirements for the next day operations planning process. This includes performing system studies and security analysis to ensure that bulk power systems can be operated in anticipated normal contingency conditions. This can only be done if the reliability coordinator has the authority to manage outages to transmission and generation facilities to ensure that limits will not be violated.

Limits protect against voltage instability and are dependent on minimum voltages being maintained, adequate reactive resources being ensured and the planning time frame through a comprehensive outage management process.

While it is important to obtain from neighboring reliability areas that impact on your area, it is not important to have visibility of all limits within a neighboring area. This can lead to confusion where interpretation of limits is required or where patrol actions are already in place in that neighboring area that might mitigate the impact of the contingency.

What actions are appropriate when mission critical monitoring and control systems fail? A system operator's tools must have a high degree of reliability obtained through a redundant infrastructure and carefully controlled change management process.

We talked a little bit about change management and the impact on software applications earlier today and I think that's an important aspect that we have to manage in maintaining our software.

NERC policy nine requires a reliability coordinator to have continuous monitoring of the reliability area including provisions for back up facilities.

Policy six requires control areas to have a plan to continue operation in the event its control center becomes inoperable. However it does not address this as reliability coordinators. Coordinators must have a complete set of back up tools.

While defining the required tools is essential, it is equally important to recognize their limitations. If tools fail the back up is competence, experience, preparedness and knowledge of operating staff. These should translate into the ability to (1) correctly interpret the results presented by the tools, (2) adequately assess system conditions when the tools fail, (3) and finally to act independently without confirmation by the tools to ensure that the system is operating at a secure state.

Thank you.

MR. CAULEY: The third presenter on this panel is Stephen Lee of EPRI, E-P-R-I.

MR. LEE: I would like to preface this by some general comment. What EPRI is saying here is not new. It is very common knowledge in industry for a number of years.

Gerry, next slide please.

(Slide.)

The research community really needs the support and commitment of the entire industry to fix the reliability problems. Restructuring really has not been accompanied by (inaudible) commitment of resources to implement critical pieces of infrastructures such as transmission capacities and information technologies and, also, not enough commitment to fund research and development.

Next slide.

(Slide.)

This a chart that shows the U.S. electric R&D ranks in the bottom 20 industries. We do better than railroads but we spend less money as percent of our revenue than restaurants.

In 1999 according to NSF the total U.S. R&D in electricity industry is only about $422 million and I know it's been declining because average funding has been since declining about 10 to 20 percent a year.

Next slide please.

(Slide.)

On -- observability, the fundamental operation grid has changed in the size of the network and the monitoring of a particular authority has grown due to the merging of functions in reliability coordination being a human process brought time delay and potential human errors. Both may result in less reliability so we may need to make reliability criteria more stringent recognizing this transition problem.

Observability really requires accurate topology of the network. In the N - 1 criteria in the 30 minutes to bring back into compliance should be examined for adequacy in view of the effective restructuring and its transition effect on operational complexities and in sufficient training.

The effect of network size and larger footprints, the effect of uncertain and long distance power transfers, the effect of time delays introduced by congestion management rules and tools such as IDC and COR, the effect of an adequate of state estimator and IDC or topology changes and realities of the N - 1 criterion really does not explicit account for human errors, EMS alarm failures and hidden relay errors which are really the major causes of blackouts.

So 30 minutes may not be realistic because of this human process. N - 1 itself may not provide sufficient reliability margins so a study to establish the equipment reliability and proposed restructuring would be useful for establishing new reliability criteria and also probabilistic approaches should be seriously considered for transmission reliability.

Next slide.

(Slide.)

Our displays, yes, we definitely need dynamic map boards and other displays such as wide area displays fur situation awareness within home areas and across the entire interconnection. For example, line close outages, dynamic megawatt and megabar reserves, with accurate and common data sources for common viewing that includes geographical displays, bubble diagrams showing wholesale power transactions and also visualization of transmission bottlenecks and particular dynamic or real time transfer limits, for example, using the community activity room display.

Next?

(Slide.)

About minimum sub (inaudible) wide area monitoring display, performance should be measured by the time lag to explain retro values inside of 30 seconds to measure data or five minutes for network topology data and a system availability should be very high approaching that of the EMS system such as 99.99 percent of availability.

Congestion management II needs to expand beyond its own footprint either using LMP or IDC and also be coordinated with other grid displays in the same interconnection, for example, by applying the virtual RTO concept.

We need system separation capability. Well defined system separation boundaries can actually speed up system restoration with proper training so we have really got emergency resolution procedures based on well defined boundaries and should be multiplied sets of boundaries to restore the system faster.

In operator training simulators with snapshot capability for off line studies can be very useful and helpful for operators for doing emergency situation restoration to solve real time problems they have not been trained on before or encountered.

Next slide.

(Slide.)

About SKADA and EMS functions -- in addition to state estimators we need to have topology estimation. Each realiabilty coordinator should have one topology estimator for rapid detection of line outages and the topology estimator should automatically update the NERC SDX continuously for the IDC and TRR process and before the TE is operational we should require the SDX to be updated frequently and regularly.

The state estimator does not work by itself. It must be well supported by trained engineers on all shifts and have a system availability greater than 99.99 percent.

We also need on line contingency analysis, on line voltage stability analysis, and on line dynamic stability analysis.

And something new that has to be developed is intelligent alarm processing which includes operator advisor to help operators really understand what is going on in the system and also in the area of under frequency and under voltage load shedding, these schemes need to be examined and developed and well coordinated.

Next slide.

(Slide.)

As back up tools operator training simulators are really inexpensive and highly effective for training operators. Customized OTS replicating EMS will improve operator effectiveness through regular drills and P/C based OTS with small generic power grids and well developed training exercises will help operators identify, analyze and respond to unfamiliar operating conditions which often appear under emergencies, classroom instruction and self training materials to education operators on the engineering fundamentals of power system dynamics, for example, the EPRI power system dynamic tutorial report.

Finally, web based OTS would be useful for coordinated training of drills among grid operators and transmission operators.

Next and final slide.

(Slide.)

Are SKADA and EMS systems being properly maintained?

I just want to bring out one point, that alarm system and EMS software need to be really tested under stress and heavy loading conditions so we know for sure they will work properly under severe conditions.

Thank you.

MR. CAULEY: Okay thanks Steve.

The next speaker is Victoria Doumtchenko -- I hope that's close enough -- and she's with MPR, which is a human factors based company out of Northern Virginia.

So correct me where I missed your name or your company.

MS. DOUMTCHENKO: Okay.

Good afternoon. My name is Victoria Doumtchenko, that was right. I am with MPR Associates. We are an engineering consulting company in Alexandria, Virginia. Actually our business is in nuclear and non nuclear energy and power and human factors is one of the specialties, I guess, that we deal in.

What I wanted to talk about today is actually to give a brief summary in our report findings that we looked at that were particularly of interest to us to provide some conclusions and recommendations and also talk about the benefits of the application of the human factors engineering process to control centers.

The Interim Report identified a number of electrical computer and human events as causes of the initiation of the blackout. What we noted as important was that computer failures were probably indicative not only of equipment problems but also the computer failures led to the loss of situation awareness in the control room.

Next slide please?

(Slide.)

There were another number of -- I'm sorry, there were a number of other reasons cited, among those are --

human errors, lack of procedures or inadequate procedures, something that people have talked about a number of times today, lack of monitoring tools for high level visualization, lack of alarm indicating unavailability of alarm systems and other supporting information systems.

I want to point this one out as probably one of the highest priority problems that we saw.

Also lack of visibility of the status of key transmission elements in neighboring systems, basically a lack of adequate data provided to the operators that would probably enable them to make the decisions on a timely basis and make correct decisions and finally inadequate operator training, again, something that we talked about a number of times today.

The conclusion that we came to after analyzing this in the Interim Report findings was that probably a failure to appropriately include human factors engineering into the design of the control centers and training of the operators may have been the major contributing factor to the events of the blackout.

The recommendation that we provide is to apply human factors engineering process consistent with the so-called "graded approach" to derive practical focus benefits.

Now the term "graded approach" comes from the nuclear industry actually. It's an NRC defined term. It's a well documented research and mature process which basically says that human factors engineering needs to be tailored to specific application applied to the degree commensurate with the level of effort required to understand what is important for a particular situation or application.

Next slide please?

(Slide.)

The benefit that we see would come out of the application of human factors engineering to control centers would be first of all helping to ensure that situational awareness is maintained under all operating conditions and we're talking about normal operating conditions and emergency operating conditions, of course.

The type of recommendations typically as an example that would come out of this kind of evaluation process would include providing a control center-wide indication of multiple alarm system failure, providing an effective functional overview display, also improving alarm presentation and alarm prioritization to make alarms more intelligent and minimize the number of nuisance alarms and alarms that demand an operator response.

I want to mention that, as far as alarm presentation prioritization is concerned, there has been sufficient -- there has been a lot -- of research done and MPR has participated in that. There are some publications available, some reports that we have produced for the research sponsored by EPRI and you see the references on the slide.

Some other benefits would include -- next slide please --

(Slide)

-- improving crew coordination and in their area the type of recommendations the type of benefits I guess we would see is improving procedures, training, improving communications and improving peer checking.

We would also seek to decrease the probability of human error currently -- the recommendation that we would like to provide is to use human reliability analysis to identify design teachers to minimize human error, allow detection of human error and also -- very important -- provide an accurate recovery capability.

Another couple of benefits here is to minimize the potential for and the consequences of, failures when human errors or human failures occur so we need to understand that we can try to minimize human error but this is not something that we can avoid.

So for that, we would stick to use failure modes and effects analysis to identify this kind of failure, both human and equipment failures, and understand their effect on operations.

Last but not least is helping to ensure that both test requirements and human capabilities are appropriately included in the design so what we're talking about here is using task analysis to make sure that requirements for displays that are processing controls displays and alarms communications and operator support aids are identified and appropriately included into this design to make sure that the operators can accomplish the tasks that they need to accomplish under all operating conditions and under any operating mode we can think of.

The reason why we think this approach is going to work is because human factor engineering is not new. In fact, MPR and the nuclear industry as a whole have a lot of experience with that.

Of course, the TMI II accident was probably the starting point where people started paying attention to that. Basically what we saw was that the TMI II accident showed that, at the heart of it was a simply human factors interface problem.

All nuclear plants were required to perform a detailed control room design review following the accident and a whole number of problems were discovered and a number of modifications were made as a result of the VCR DR effort.

Those included improving human system interface, operator performance, performing alarm systems upgrade, including the one that I mentioned in the beginning of the presentation -- providing an indication that an alarm system is no longer functioning.

Also, human factors engineering reviews were incorporated into the indemnification process and system health monitoring was also provided.

So the bottom line is we know that the August 14 event showed us that significant human factors issues exist in control centers. There is however a well defined methodology that we think can help evaluate these issues and find practical solutions and we recommend the human factors engineering process because we see there are some clear benefits that can be derived from that.

Most importantly we can reduce risk and increase the reliability of operations.

Thank you.

MR. CAULEY: Thank you Victoria.

And the final speaker for the panel is Don Watkins of the Bonneville Power Administration and Don is working with Vicky Van Zandt and also Tim Cousy from the NEB in Canada who couldn't be here today and Don is filling for him but they're all on the operations investigation team and Don has a few closing comments on this topic.

MR. WATKINS: A few? More than a few.

So hear me out because all of this has been said very similarly -- things that we've had different perspectives on -- and I know it's hard to listen but I'm going to speak fast just like most of these guys did because there's a lot of stuff.

So throw away a lot of stuff but there may be a few things in there to get.

The first note I want to make is from an earlier presentation because I think it's really key to our culture. It's not just our tools. And it's about the inquisitiveness -- and it was spoken of with regard to operators -- but I think that's a real high need we have all over and that is borne out of visiting some of the key control centers in this blackout and listening to hours of transcripts and this and that.

We do our job routine stuff 99 percent of the time and the average is zero percent that operators or engineers or managers have to deal with true blackouts or disturbance -- is zero, right? The average effectively, right? Because very few -- only a few people on a shift in a few utilities.

So we need to think about how do we think outside the box? I won't say any more on that but we need to think about that at the root because we can have all the tools, all the systems, all the processes, all the monitors and, if we're not thinking outside the box, we'll still miss it.

So what's the criteria for observability? And I went more generically because these are all really relevant. You have the breadth, the resolution, the accuracy and the timeliness. And these were all issues in this blackout.

The breadth really has to do with a lot of stuff and one of those is you've got to look at your lower voltage systems, too. Your lower voltage systems usually have limits and they have a lot of the reactives, so if you're modeling it, you need to look at those.

Another part is you need to know your breaker status and all of your analogue information and you not only need it for your system jurisdiction, you need it into the area that you could affect or the area that could affect you.

And that stretches a number of busses out from your direct area of control.

The other thing you should know is, let's say Bob comes up here with a nomogram for you about Lake Erie and it might involve -- I don't know if he's going to -- but it might involve the IMO, Eastern Pennsylvania and all the way through, right? Detroit, the whole thing through.

In that case, if that's part of the nomogram and you're part of it, you really should be able to see all of the information around that that involves that nomogram. You need to see that data.

So that's the breadth. That's -- really important. All these are, though.

Resolution is really important and that really speaks more specifically to the lower voltage. You'll hear a lot when you start speaking about reliability coordinators and ISOs. You'll be hearing about 230 and above and the problem is, at least in our system and I think -- I know it's true -- of this system, too, a lot of limits, parallel lines are in the 138, the 115, the 69, the 39 kV stuff.

Just beware, that's important.

Accuracy. Accuracy really messes up state estimators. If you've got really bad data in which -- trust me, when we started doing data exchange, and I'm sure it's the same in the East, there's a lot of rotten data out there. I mean, you're getting it but it's bad. And it really messes up state estimators, right? It confuses them. It makes them not solve sometimes and give bad results.

So be careful.

Also -- I need to see what I was saying here.

You have a tool to check accuracy and it's a very effective tool and it's probably the main thing you can use this tool for is the state estimator because it tells you when your data isn't matching right. It tells you mismatches and how much it has to correct and, if you pay attention to it, you'll go out and get technicians out there and they'll adjust those values so they fit so you have a tool to get your data accurate.

The next one is timeliness. There were a lot of problems with timeliness on August 14. A lot of problems. And timeliness is about seeing the same data at the same time. There were a lot of conversations were people were seeing different snapshots of the same data and they were different -- some were really high, some showed huge overloads -- and yet they weren't sure and they didn't trust the numbers because the others didn't have the same number. It leads to a fuzziness in the brain and you don't act as quickly when you don't have it.

So I'm going to suggest there's a couple things. One is you have a time skew due to your data samplings, right? The rates of scatter samples? Usually that's pretty fast, though. You have a time skew due to data transmission. A lot of the data is picked up by the ISO reliability coordinators at 30 second increments. That is great if you're dealing with hourly problems, right? The stuff you can do at TLR for the next hour.

But if you're dealing with an emergency right now where lines are going down, lines are overloading and so on, 30 seconds is way too long especially on status, although I know sometimes status updates more quickly.

And the last one is, when you're looking at a state estimator, that also has a skew. It may be anywhere from the 90 seconds as described by Dave to five minutes and five minutes is a reasonable period to run on a state estimator.

Beware. Operators should be probably using raw data and using the SE to do the tools and also just to check data.

The next thing -- and going to the next question here -- oh, by the way, think on a time skew, I would think that on all of these things, you should move everything in terms of data transmission and sampling rates to the five-second timeframe. Think about that, because that's still going to allow some time skew. It could be ten seconds or so out, but just think in terms of that.

Are dynamic map board essential for maintaining broad overviews? We have good scatter displays, and there's been quite a move to move away from even having map boards.

And there are some utilities that do not have map boards, and there are some that have them, but they're pretty static; there's only a little bit of information. So I don't know the right answer to that, but I do know that you need someplace where you can look at the same information, the same way, every time, and when you have a map board, whether it's a projected one like Dave was talking about, which hopefully is the same one almost all the time there, or whether it's tiles, with the lights and some analog values in them.

What happens is that when you walk into that control room, you know exactly what you've got by exactly where the lights are. You can assess your system just like that, because it's the same except for what's changed in terms of breaker statuses and values. So, map boards are really important from that perspective. They give you a larger overview, very quickly, and you'd assess it just like that.

If you're looking at displays, sometimes it's not that way because displays keep changing. It's just the way it is.

The problem with all of these though, all of the dynamic stuff, is that it's usually driven by the EMS system, as all our strip charts are these days. So if you lose your EMS system -- this is going to answer a later question, too -- if you lose your EMS system, you're often gone, and so you need to think carefully about that.

One way would to be to provide some alternative paths to feeing a map board and maybe stripping information off of RTUs before they get into the EMS scatter system.

What minimum set of operating tools should the operators and reliability coordinators have? I'm going to deviate a little bit, so try to listen, and you can ignore me and not like it if you don't.

But I think that at the root of a lot of our issues is that while our power systems are extremely complex, they are extremely complex from an engineering point of view, and we've done amazing things with control and operation of systems, let no one fool you. It's an amazing system, but I'm going to suggest that our methods of transmitting data between our utilities about the transactions we're doing and the ability to change those in real time and learn from our data, is abysmal.

We don't -- we're developing that, but we do not have real good data exchange methodologies and common open standards for doing that. And I'm going to suggest that this is essential.

If we know our transactions and we can look at those from the birth of the transaction, whether it's a bilateral deal for energy that has to find transmission eventually, right, and then has to be settled, even that, as well as all our power system information, our models for business and for the physical system, if we get those in there, then we can see them, we can see all the causes and effects, and we can also influence them.

If we had transaction systems in a standard, common, open system, a real-time operator could go hit a couple buttons, because all the information is there, and send that information to the parties and they take care of it, you know, as far as adjusting generators and so on.

There was a mentioning of the over -dependence on the telephone. We need to get off of that into a dependence on reliable data systems that pass the key information between us in an open, standard way, not a bunch of separate ways.

We need better models. Do you know whether your AVR on a generator is running, is on or not, is really important? And for us, whether your power system stabilizers are on or not really matters, too. And we don't get that information commonly in our RTUs and so on.

So the other problem we have is that even though we have models of everything on the system, a lot of it isn' right, how we model our responses to things, how we model what happens with TAPs, and there's just a lot of stuff. When you get into studies, you find out our models aren't really good. We need to work on those. So those are tools.

We've already talked about online tools. It's just important. Those are deeply important, and we only do thermal right now. We really need to think about voltage stability, and we really need to think about dynamic stability.

There are problems there, and sometimes I think there are a lot of problems and we don't even have a clue about them because they come and they go and we're just lucky nothing happens. So, there's a lot of work to get to that, but we need to do it.

So, let me tell you something else: Online tools, they quit in the most important times you could imagine. And ask MISO, you know, about August 14th.

They have good tools and they're reliable, and while they were called developmental, they were pretty well developed. And they didn't work during that period, and there were others that didn't, and quit at various times.

So you need to -- so this is my lead-in to say that you also need to have good offline tools. You need to have good offline study tools. That means keep your models up to date. If you're responsible for operation, keep your offline, whether it's a PTI or GE database or an IEEE, whatever it is, keep a database that's fairly up to speed so that you can quickly look at your system and study it, because your online tools may not be there when you need them.

We need tools to accomplish real-time load shedding. You need to be able to dial in -- and this isn't everywhere and you can't do it in some places, but where possible, we need to be able to dial a number and do our SCADA system and have it trip that amount of load within sub-minutes. That's important.

Hopefully we'll never use it, but they need to be in our tools.

MR. CAULEY: Don, two minutes.

MR. WATKINS: Okay, I'm going to move quickly.

And the last one on the tools is, we need robust tools, and by "robustness," I mean, is my system healthy? Right now, we do our study tools, all based on our assumptions of what the models are, what the contingencies are, what ails the system.

And somehow we need to identify key indicators of the system health. You know, our doctor looks at our throat, looks in our ears, takes our blood pressure and our temperature and so on to determine whether we're healthy or not. We need those same tools in the power system, so if we're wrong in our analysis, it still may capture instabilities or things that aren't healthy in our system.

Often there are voltages that change. You know, when your power changes a little bit and you want to look at how much your voltage changes, sometimes that changes, and that's an indicator of ill health. Sometimes your angles are really high on the system, your power angles, and sometimes those are indicators of bad health.

Sometimes there are oscillations going on, kind of in the background that aren't damping; those are indicators of health. We need to look at tools that take responsibility for the fact that we might be wrong in our assessments of all that we know in our infinite wisdom about the system.

So I'm looking through what I'm going to say quickly here, because I'm just about out of time.

So, I'm going to go, what is appropriate for mission-critical monitoring and control systems? What if they fail?

I'm going to say that you almost have no alternatives if these fail. If your control systems fail, you're really in a heap of trouble. The best you can do is what First Energy was doing a good job as they started realizing their system had failed; they were calling out operators to go to different stations.

But that's not going to work. I mean, they're looking at something in their station, they have to get there, and your system could be in a lot of trouble. So I would suggest, and I'm sure there are things you should do, but the thing you should focus on is keeping a very redundant, extremely reliable control system for your bulk grid stuff.

You know, you might be able to afford some distribution things or sub-transmission, but when you're looking at your bulk grid, you better have very, very good tools, have them redundant, and you probably better have a really good backup control center that can take full control and not have common mode failures.

And that is all I'm going to say.

MR. CAULEY: When the transcriber's fingers caught on fire, I knew we had to bring that to a close.

(Laughter.)

MR. CAULEY: I heard somebody running back there with a fire extinguisher.

(Laughter.)

MR. CAULEY: I know you're all hungry and would like to go on a break, but I would like to catch, if there's any sort of momentum of burning issues and questions from our distinguished investigating management team, and we'll do that for just a few minutes and then we'll break and come back to the questions, further questioning of this panel. I don't want to short-change it, but I'd like to catch any burning high priority issues before we break for lunch. I see Alison is ready to speak.

MS. SILVERSTEIN: I have one --

MR. CAULEY: This is Alison.

MS. SILVERSTEIN: Alison Silverstein, Federal Energy Regulatory Commission. Sorry I was late. I had to give a speech.

The question is this: Y'all have given us a great list of tools that everybody ought to have, but particularly for Steve, how many of those tools are ready for prime time in terms of -- they would all be great things, but how many of them can I buy off the shelf or pull out of a box today?

MR. LEE: (Inaudible) one of the pretty good tools commercially available, right? The varieties of wide-area type displays, too, are also available. So I think these are two set of tools that are immediately available.

Alarm processing projects, the operator have advisory type of tools, are still in development, so, there are certain other tools that need to be developed for quicker deployment.

MS. SILVERSTEIN: Anyone else?

MR. WATKINS: I would just say that a lot of the tools that we talked about are available. They just need development and a lot of stuff to be done that would get you 80 or 90 percent of the way.

MS. SILVERSTEIN: When you say they are available but they need development, what does that mean?

MR. WATKINS: You know, the problem isn't the algorithm, often. A state estimator and the contingency analysis tools, the real problem usually isn't the algorithm itself; the biggest problem is simulating the data and making that work and getting automatic ways of reflecting changes in the topology, et cetera. And that takes a lot of resources.

MS. SILVERSTEIN: Does that it mean it's the dataset collection and the tailoring and the care and feeding of these things that's really the challenge?

MR. WATKINS: Yes.

MS. SILVERSTEIN: Not the acquisition of the tool itself?

MR. WATKINS: Almost everybody has a tool and offers it, but making it work is a whole different issue.

MS. SILVERSTEIN: Thank you.

MR. CAULEY: Any other questions? Dave Hilt?

MR. HILT: I just have one: I appreciate that because we had asked earlier this morning -- and, Alison, you didn't get to hear it, but I would ask this panel the same thing. We were talking about having wide area monitoring and effective tools to do that, and was there any shortcomings in terms of developmental activities by software vendors, et cetera, whether there were some things that the industry needed to address or encourage along those lines.

Secondly, though, I want to talk a little bit about -- I know Pat mentioned lost the primary the primary control center, as did David, as did Don, all of you talked about that a little bit.

And some of you folks talked specifically about for the reliability coordinator, that they did have to have a backup center, needed to have that. Don just talked a little bit about the control area net and having that. I know that the standard does not require that. It says that they have to have a plan for the loss of the center, but your view of it was that they needed to have a major transmission system and you really needed to have an active backup control center.

Is there a size where you think that's necessary or is there some cutoff? Certainly there are a lot of small control areas out there. What's your view on that as to at what point you think really a backup control center is absolutely necessary, versus doing what you were talking about, manning the various substations?

MR. WATKINS: So you've heard the comment that the devil is in the details. So we make this wide, sweeping statement that says that for the bulk grid, you shall have backup control centers, but then we'll have an age-old year of argument over it, over how big is that?

All I know is that we're moving toward very large integration for the reliability authority and responsibility. If you look at PJM New York, New England, you look at ERCOT, you look at the California ISO, Bonneville runs most of the bulk grid in the Northwest.

Those certainly are the size that they better have very good stuff. I'd say anything that serves several major population centers, you know, several towns of several hundred thousand or more, you know, something that gets where you're affecting the whole economy, the industry, et cetera, of a fairly large area.

MR. HILT: Just from a business continuity standpoint, if nothing else.

MR. CAULEY: Tom or David?

MR. MEYER: Just a comment.

MR. CAULEY: This is Dave Meyer, DOE, for our online people.

MR. MEYER: A comment that others may wan to amplify on: I'm struck at how many times I've heard about the interlock between training operators and the use of tools, particularly new tools.

I've already heard stories from some of you about what seems to be a relatively slow rate of adoption of some of the new tools that have become available recently. So one of the lessons that I'm getting out of this is the importance of training in order to use the tools that we do have available.

MR. RUSNOV: Dave has covered a couple of my comments. My other comment is that I guess the panel reminded me of back in the days when I actually did some load flows and transient stability studies, and every time I picked up a base case, I was almost terrified of opening up the damn thing because of the number of errors.

The errors came about honestly. (Inaudible) wants to do a particular study and says, well, that piece of data doesn't matter, and I don't have the precise information, so I'm simply going to put it in an approximation. It's good enough for what I'm doing. They do that without ever removing it, and it stays in the damn thing until ultimately you get a large accumulation of bad representation of transformer TAP changers or generator controls, et cetera, something that really has to be watched.

MR. CAULEY: Alison, another one?

MS. SILVERSTEIN: I'm trying to figure out how to ask this question so that I get the right answer. I don't want to ask who has or what organizations have the best tools out there, but rather for the kinds of tools that y'all are recommending, can you tell us individual or a tool and an organization that has the best kind of thing out there, so that we can get a sense of who's got the best stuff? What are we looking for? Does anybody have all the tools that are needed?

MR. CAULEY: Is that a rhetorical question?

(Laughter.)

MS. SILVERSTEIN: I didn't think so.

MR. WATKINS: There's a bunch of tools. You know, the online tools are well established in the planning environment, and there are three or four providers for that and we know who those are.

But those will have problems, you know, as mentioned. The online tools, you know, I think that the three larger of the companies, AVB and ESKA and Siemans, provide good tools, you know, for doing that.

I think each utility needs to understand that they need to understand what's involved with managing those tools or implementing those tools. I think that's where we've fallen down.

With our vendor, we've had the tools for many years, but it's taken us years to get them where they are accurate. So the tools that -- I think I better shut up.

MR. CAULEY: We stuck our toe over the antitrust line, just a tad for you there, with not mentioning vendors' names and if you want to submit response to that in terms of specific vendors that you think have certain tools, I'd ask you to do that after the conference with Alison.

Any other generic response to the question?

(No response.)

MR. CAULEY: Okay. What I think we should do is, it's 12:30. I appreciate your patience in enduring the extra half hour here. But I think it puts us in good position to wrap up this afternoon in a timely manner, you know, sometime between 4:00 and 4:30, hopefully, because we're just a tad ahead of schedule.

When we come back from lunch, we will ask again if there are any further questions of this panel or anything we've covered in the morning, and then we'll go into Panels D and E. I'd like to get the panels for D and E to bring me your presentations now during lunch.

I will be so bold as to say, even though we don't have lunch served, that we can be back in one hour and restart at 1:30, with the hope of getting out of here by 4:00. Thank you.

(Whereupon, at 12:30 p.m., the technical conference was recessed for luncheon, to be reconvened this same date at 1:30 p.m.)

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AFTERNOON SESSION

(1:40 p.m.)

MR. CAULEY: I need to get the Panel D folks up here, Panel D, Paul Roman, Frank Macedo.

(Pause.)

I appreciate you all making a rapid turnaround on lunch. That will let us stay on track and make all our travel arrangements this afternoon.

Before we launch into Panel D, what I'd like to do is see if there's any other questions or comments from this morning's session, in case you hadn't digested it over your lunch. The three panels this morning were focused more on operational issues, reliability coordination, operator tools, emergency response, and so on. This afternoon is going to focus more on system planning, design, and analysis and protection, and so it's a good time to pause here and see if there are any questions left over from this morning, particularly for Panel C. We kind of cut them short there before lunch. And Myer Sason (ph.) of Con Edison has his hand elevated.

MR. SASON: Yes, as far as Panel C, I just had one comment. One of the things that was discussed was the need to make sure that like transactions that are being made, seem to work, bilateral transactions was mentioned, but somehow that information needs to be brought to a single place so it can be evaluated from the point of view of reliability.

And I just wanted to say that's what SMD is all about, that's what the LMP systems are all about. Those systems like in PJM, New York, New England, that have LMP, what's scheduled is what's reliable. And if it's not reliable, it's not scheduled that way; it's rescheduled, maybe at a higher cost, but in a way that it is reliable.

So under no conditions are any of these reliability coordinators, ISOs, RTOs, scheduling either day-ahead or real-time unreliable power flows, and not from a point of view of normal, but also from a point of view of contingency.

So I thought that comment might be useful on the previous panel. Thank you.

MR. CAULEY: Okay. Any other comments or questions or inputs to the Panel C or any of the three panels this morning?

(No response.)

MR. CAULEY: Okay, we'll move on into Panel D, which is looking at system planning, design, and maintenance issues. And we'll start off with our expert panel with Paul Roman from NPCC.

MR. ROMAN: Yes, my name is Paul Roman. I'm a member of the NPCC staff, and my presentation today will address six of the seven Panel D questions. Next slide, Gerry, please.

(Slide.)

MR. ROMAN: Okay, the Northeast Power Coordinating Council or NPCC, is the regional electric reliability organization for Northeastern North America, and it consists of the Province of Ontario, New York State, the New England states, the Province of Quebec and the Maritime Provinces. And those are also the respective NPCC areas.

Next slide, Gerry, please.

(Slide.)

MR. ROMAN: Okay, Question 1 deals with the seasonal and planning assessment studies that are conducted. In NPCC, we participate on quite a few of these appraisal studies or we conduct them.

First of all, there's the NPCC overall system assessment study, and this addresses all aspects of system operation, and it also covers the thermal limits on the system and the bulk power system, the stability limits, and also voltage limits.

In addition, there's also a probabelistic assessment that's done for each summer, and that determines the loss-of-load expectations of the NPCC areas.

Another study we participate in is the MEN seasonal appraisals. And MEN stands for the MAC, ECAR, and

NPCC regions. And in these studies, we determine the directional, region-to-region transfer capabilities and also we conduct simultaneous transfer capabilities, and we determine those limits for these wide-area-type transfers.

Now, in addition, within NPCC, the individual areas also conduct detailed studies where they look at more localized type transfers and more localized type limits. Also within NPCC, the NPCC areas are required each year to do reviews of future transmission and resource adequacy.

Now, in conducting these studies, the NPCC areas must follow the NPCC planning and operating criteria. And this is really referred to as the basic criteria and it's included in or it's contained in the A-2 document.

I'd just like to mention that all of the NPCC documents, the criteria, guidelines, and the procedures, are all accessible from the NPCC website.

Now, the NPCC operating and planning criteria establishes a design basis approach, in that the system is designed to withstand certain contingencies, certain types of contingencies, and then that's consistent with the operation of the system, that is, the system must also withstand those same types of contingencies.

Now, included in the contingencies are, first of all, loss of single-element or N-1 contingencies, but also in our criteria, we do have contingencies that result in the loss of multiple elements. Examples of these include, tower fault or as a result of delayed clearing, you could result in -- may result in the loss of two or more elements.

Now, one thing I'd like to point out: I guess it had been pointed out by some other speakers earlier, that these criteria are -- they do meet the NERC requirements, but in some of these cases, they exceed NERC requirements and they also exceed what most other reliability regions require.

And some of this is the result of lessons learned from past blackouts like 1965, 1977. Some of that resulted in looking and doing these things.

Question 2: This addresses the system models and the accuracy of the system models that we use in the assessment studies, and we feel that within NPCC, the models we use are conservative in the power flow and dynamic system studies that we conduct.

First of all, we model peak loads. For the reactive component of the loads, we use the best estimates we have. In addition to generation dispatch, you try to choose generation dispatch that stresses the system, and you also do that for the type of transfers that you simulate.

Now, regarding the generator reactive output limits, those generally are limits that have been demonstrated through actual testing at full capability of the machines. You know, we tried to institute the testing as part of determining, you know, what should we use in studies?

Now, the development of the models, the base cases we use, do go through extensive fine-tuning at several different stages. The go through the NERC MMWG process. Also within NPCC, we have a similar process. It's through the SS-37 working group and also the individual NPCC areas go through a lot of fine-tuning of these cases.

I know that the question came up earlier about as far as finding errors in these, well, you know, you try the best you can to clean them out, and it depends on how dedicated you are to doing that.

In addition, we have an NPCC procedure, the C-29 document that does outline and indicates the procedures for system modeling, addresses data requirements and facility ratings.

Okay.

(Slide.)

MR. ROMAN: Question 3 addresses facility ratings that are used in studies. Now, the normal and emergency ratings are actually established by the facility owners and they use area-specific parameters that are consistent with that last document I referred to, the C-29 or the system modeling document.

Coordination of ratings: Well, they are coordinated on a regional basis, and a lot of that coordination is done through the base case development and fine tuning process where you see the neighboring regions or neighboring systems try to make -- you have to be consistent on tie lines and that's a big part of that.

In addition, we do have procedures in place to relieve and deal with overloads, should they occur, so that is something we also do have in place, those kinds of formal procedures.

Question 4 deals with voltage support, voltage control, and the adequacy of reactive reserves that we maintain on the system. Now, the NPCC area planning and operating studies actually evaluate the system voltage limits.

Within NPCC, there has been emphasis on voltage limits and voltage control for a very long time. The actual -- some of the major interfaces within NPCC areas are voltage-limited, and the limits are calculated and significant margins are applied to determine where do you actually operate to.

And in addition, we've added reactive control devices over the years -- shunt capacitors -- but there are also a number of static compensators on the NPCC systems, and we've also had a fax device added in the middle of New

York State a few years back.

In NPCC, we do have a guideline regarding the inter-area voltage coordination. That's the B-3 document, and that indicates some of the guidelines for how to do voltage control in the bulk power system. In addition, there's an accompanying document, the C-4 document, for monitoring that guideline.

I'd also like to point out that within NPCC, the reactive resources are essentially coordinated, and that is because each of the areas is an essential operator. They also have control to control voltage resources such as switching capacitors, reactive limits, things like that, ordering plants to higher limits.

Regarding Question 6, this is related to the evaluation of simultaneous transfer capabilities, and as I mentioned earlier, the MEN studies, as part of those seasonal studies, every time, they do calculate simultaneous transfers for wide area type transfers.

Now, I'd also like to point out, too, that in those studies, they compare operating points to the previous year's study to try to validate that you are operating within the limits that had been calculated, to really try to provide some validation for operation versus what you'd done in these studies to show on a seasonal basis, what you expect.

We've also been involved in some other related type regional studies such as the Regional Planning Forum and also the Lake Erie Emergency Redispatch.

Now, regarding contingencies evaluated, I did mention that earlier about the basic criteria document, and that the criteria do tend to be more stringent than what's required at NERC and what other regions use. I also, I think it was pointed out earlier that some of the areas also can have more stringent criteria, and in some cases, they do. An example is southeastern New York.

Also, we do in NPCC, have provisions in the basic criteria for conditions where we operate under high-risk conditions, so that is something we formally have in the procedures. And just in summary, based on the seasonal assessments that we do, system modeling we have, and the criteria we have in place, we do feel those are adequate to avoid and minimize the occurrence of major outages.

Now, obviously through the blackout, the August 14th blackout, we are looking and trying to look into that to try to review and come up with lessons learned.

And just as I pointed out, at the NPCC website, you an access all of our documents there, and it's indicated on the slide as npcc.org.

MR. CAULEY: Our second panelist is Shinichi Imai, from Tokyo Electric.

MR. IMAI: My name is Shinichi Imai. I am from Tokyo Electric Power Company in Japan. I have more than ten years of experience of power system operation and for system protection.

I really appreciate this opportunity to make a presentation about our recommendations based on our experience of voltage instability in 1987.

Yes, I would like to focus on the Question No. 4, Voltage Issues. Next, please.

(Slide.)

MR. IMAI: Tokyo Electric Power Company is the largest investor-owned utility in Japan. We mainly supply the electricity to the nation's capital of Tokyo, and the highest demand, 64 gigawatts, was recorded two years ago.

Next, please.

(Slide.)

MR. IMAI: In July 1987, TEPCO experienced an extensive outage caused by voltage instability, not contingencies, but rapid demand increment, led to the situation of no power flow situation, so no power flow solution, which was voltage instability.

During voltage collapse, (inaudible) were activated and 2.8 million customers of eight gigawatts were lost. Next, please.

(Slide.)

MR. IMAI: Since then, TEPCO has enhanced power transfer capability by installing numerous switches, shunt capacitors of 18 gigavolts and synchronized condensers to (inaudible) substations.

They have been planned so that the voltage instability can be prevented against any single contingency in summer peak conditions. If (inaudible) of regulated EHV bus voltage is detected by automatic controller, they are switched automatically within a few seconds, therefore, TEPCO shunt capacitors can be regarded as dynamic reactive power resources, because they can react rapidly enough to maintain voltage during voltage collapse.

Next, please?

(Slide.)

MR. IMAI: Our observation on August 14 blackout: We found in some sense, reactive power supply in the Midwest from report. Next, please.

(Slide.)

MR. IMAI: Skip this one. That's our recommendations: Number one: Install more reactive power resources; No. 2, use alternative for dynamic reactive power resources. Next, please.

(Slide.)

MR. IMAI: Reactive power is caused by long distance for transactions, should be compensated with a balance between static and dynamic characteristics following NERC standards. NERC standards say reactive power resources with a balance between static and dynamic characteristics shall be (inaudible). Each control area shall supply reactive power resources within its boundaries.

Each processing entity shall arrange for reactive power resources. Following these standards, we recommend the less expensive alternative for dynamic reactive power resources, based on our experience. Next, please?

(Slide.)

MR. IMAI: And Number Two, (inaudible) contingency operation like dispatching or (inaudible) reduction, based on the results of (inaudible) don't seem to be fast enough to prevent cascading outages because corrective reactions within several seconds are needed during voltage collapse.

Installation of more reactive power resources with dynamic characteristics to EHV systems can avoid too much dependence on operators against extensive voltage disturbances.

(Inaudible) installation capacitor switched by automatic controller can be reliable and economical alternative for dynamic reactive power resources to regulate EHV system voltage. Next, please.

MR. IMAI: So, we have many experience of installation of (inaudible) capacitors, controllers, dynamic power resources. Next, please.

(Slide.)

MR. IMAI: Conclusion: TEPCO's system has been enhanced by installing switches and capacitors to EHV systems, which reactors, dynamic reactive power resources against voltage instability. U.S. is installing interconnections may have enough room to install more shunt capacitors without abating voltage collapse problems because of low impedance characteristics on very (inaudible) network.

And also have U.S. (inaudible) interconnections have been operated centrally through EMS (inaudible) analysis and can be more secure by using dynamic switch shunt capacitors we recommend.

I have a feeling that the interconnections are incredibly complex and very hard to operate safely. I think that without (inaudible) system engineering, the interconnections could have never been operated securely by (inaudible).

(Inaudible) could contribute to make (inaudible) connections more robust and secure and to avoid future blackouts. Thank you for your attention.

MR. CAULEY: Thank you. The third speaker is Tap Seppa from the Valley Group.

MR. SEPPA: Thank you, ladies and gentlemen. I have quite a number of overheads here. I'm going through them at a fast clip because there will be handouts available also at the end of the presentation, and you'll see the website address where you can pick up this presentation and a couple of related presentations.

And I'll be talking only, concentrating only on the Questions 3 and 7, and just to give you a summary before I go through the presentation, there was some bad news: The bad news was that the rating assumptions in Ohio and Indiana during the day of the blackout, were totally inappropriate.

And furthermore, a number of utilities were using sag calculation methods, which were clearly likely to underestimate the sag conditions and the danger of the situation. And what is evident to us is that either NERC, FERC, or DOE must create mandatory procedures for establishing the line ratings to prevent similar occurrences.

And the good news comes when we talk about the .7, namely, there are methods to accomplish some of these procedures with moderate cost. Next one, please.

(Slide.)

MR. SEPPA: We did a study about the Ohio wind conditions on 8/14 in the afternoon. And if you look at the table there, that's 11 weather stations and note the number of zero wind speeds that were recorded there. That afternoon, there were 23 percent of the observations that were zeros, which is six times more than the occurrence of calm weather under normal conditions.

And then we took the data and we processed it using what the meteorologists call a super station principle. That means you aggregate the data and treat the hourly observations and treat the wind directions accordingly.

I'm sorry, can I get the next slide?

(Slide.)

MR. SEPPA: And this is the statistical wind speed distribution in the afternoon, and if you note, what we say is that the effective wind speed -- there was a five-percent probability of the wind speed being less than 0.6 foot per second, and 0.6 foot is actually total calm. That's when the cooling goes to the natural convection, and we believe some utilities assumed 4.4 foot per second, a safe wind speed.

You can see that that represents a 50-percent probability for that day. Next overhead, please.

(Slide.)

MR. SEPPA: What are the consequences? If you assume that your line is rated at 100 degrees C maximum temperature and you push that accordingly, and if you get a

0.6 foot per second wind speed, you can see that you will get between 25 and 57 degrees C higher temperature that what your rating assumes, provided for, and out of the 20,000 miles of lines in Ohio and Indiana, about 1,000 miles, 6,000 spans at any time on that afternoon, were operated under those assumptions. Next, please.

(Slide.)

MR. SEPPA: What does that mean for the line sag? I'm not saying that there were (inaudible) there; I'm simply saying that when you push you sag down, eventually you will meet the tree, and you can see the consequences. Conduct sag on a typical span were between two and five too much, assuming that the sag calculations were correct, but knowing that most utilities in the area use old sag tension methods which can be up to three to five feet inaccurate, we are talking about lines hanging between five and ten feet too low. Next one, please.

(Slide.)

MR. SEPPA: Now, this is not unique. This could have happened elsewhere.

The big reason is that NERC allows the transmission owners to pick up whatever numbers they want. They can calculate, they can assume any wind speed they want, and they vary around the country from zero to six foot per second.

They can calculate the sags whichever way they want. They can even eliminate the clearance buffers from their lines, if they want.

And the big problem is that the operators do not recognize, what is the primary reason for thermal limits. It's safety, public safety.

When lines sag into trees and you get 20 kiloamp faults, fortunately, they only splinter the tree. If you it sags into a school bus, you get something which is equivalent to a few sticks of dynamite. Next, please.

(Slide.)

MR. SEPPA: The other thing that operators do not recognize is -- and I read 640 pages of transcripts -- and they do not recognize that if you have a high pre-load on the line, you are starting from a point where you have essentially no time to react.

There was operator comment that said I'll just keep the line under 100 percent and not worry about it anymore. Next, please.

(Slide.)

MR. SEPPA: What's the alternative? You can monitor lines and there are utilities that monitor their lines in real time. You know, the objective is that if you look at the probability of having good cooling conditions, by far, most of the time, your lines have more capability than you think. That's the green area in this graph.

On the other hand, the red area represents times like in Ohio and Indiana on 8/14. Next one, please.

(Slide.)

MR. SEPPA: The real-time monitoring provides operators true real-time information, and there's an example of a screen at one utility that uses systems like that. You can determine the exact capability of the line that's on the left side of the screen.

On the right side of the screen, it gives the operators a clear warning. It tells the operator how much the sag is compared to the limiting value, and how much time he has under the current conditions to react before there is a clearance violation. Next, please.

(Slide.)

MR. SEPPA: Now, really now I'm talking about the Question 7. How can we deal with this with contingency management?

In summary, what you can do is, you can assume a higher wind speed or more benign overall conditions for the contingencies and dispatch your system accordingly. But you should do it only if you can monitor the system in real time, because then the operator will get an advance warning if he gets into trouble.

On the other hand, the vast majority of the time, he will not have to do anything, and you can typically increase your dispatch capabilities by 15 to 25 percent. Next, please -- oh, skip all these, please.

(Slide.)

MR. SEPPA: So what must we do to avoid more blackouts? Somebody must set clear procedures for establishing line ratings. And it should be either NERC, FERC, or DOE. I'm not saying that they should establish the line ratings; they should say what is the minimum information required.

The second one is that the operators must be trained to understand the reasons behind line ratings and the most important thing, the safety consequences. And, yes, there should be sanctions for operational lines in violation of safety codes.

The paradoxical thing is that a national electrical safety code gives you an absolute mandate, always to operate the line within safety limits, including emergencies. And on the other hand, there's no -- it's like you'd be saying don't drive through red lights but nobody would ever stop you.

(Laughter.)

MR. SEPPA: And the operation above the established limits should only be allowed if there is reliable, real-time information on the lines. Next, please.

(Slide.)

MR. SEPPA: So, what do we have as alternatives now? For 20 years, utilities have been relaxing the line ratings, and at the same time, we are pushing the systems more.

If you would want to get the same state of reliability and safety as we were 20 years ago, we would have to reduce our network throughput by about ten percent. The second alternative is, of course, let's build something. Now, here we are talking about a price tag of anything between $15 and $50 billion.

And the third alternative is to use real-time monitoring, and that can actually increase the grid capability and the cost is relatively minuscule. Next one, please.

(Slide.)

MR. SEPPA: Just a thought for you: The average transmission line in this country now dates to roughly 1970. That's like your father's Dodge.

And there is about ten percent of the lines which predate your grandfather's Ford. Next, please.

(Slide.)

MR. SEPPA: Now, you can drive these things a few minutes at 90 miles per hour, but if you do that like in Ohio, the whole afternoon, the wheels will come off. And there is work being done on that IEEE level, and there is a new Zebra (ph.) task force. You can get information on them if you go to our website, and also you can find transcripts of this and a couple of other articles. Thank you.

MR. CAULEY: Thank you. The last two presenters on this panel are working on the investigation team, and we have Bob Cummings, representing the area of modeling and analysis.

MR. CUMMINGS: Good afternoon. I'm Bob Cummings. I'm the Director of Reliability Assessments and Support Services for NERC. I got involved in the blackout immediately, almost. I was out actually trimming my lawn, but about the first beer and looking at CNN, I realized that the lights were out everywhere.

At any rate, I've been involved with, first, the sequence of events, followed by the working with the modeling area and dovetailing into the planning.

What I'd like to talk about are some of the aspects of modeling and how it relates to a few, just a few of the points in this thing. Some of the things we ran into immediately in trying to do the modeling was load representation.

In the power flow base cases, we typically use -- we have power factors that are overly optimistic. The case we picked up was a summer case at peak, and we had to substantially increase the reactive loading in order to get it to come anywhere near what we saw on the 14th.

Another one is the generation representation. We've got pretty optimistic reactive capabilities, but in many cases, they are unproven. They are untested; they are unverified.

This is not new. We saw this in WSCC back in '96, in '99 in the PJM area when they had some voltage issues. They went back and found that their generators weren't performing up to the assumptions.

Another issue that we came up against in now many fronts, both real-time and in the post mortem analysis, was line rating disagreements, not just the ratings themselves, but disagreements between one operator and another.

And, of course, the are interchange transactions. We heard some speakers earlier talking about some way of getting the transactional information up to everybody for analysis. That already has existed since 1997. It's called tagging.

It's not universally used and it's not completely used as well as it should be, but it can help an awful lot if it's done right.

However, a lot of the studies we do just aren't capturing the levels of transactions, and a simultaneous analysis has to be done. As I mentioned, there's overly optimistic power factors and incorrect circuit ratings.

We found issues where three operators had three different ratings for the same line, one, operationally, and one in a planning study and such.

Part of the problem with our power flow is that it's never benchmarked. We don't have a feedback loop from the actual system operations.

It has to be benchmarked back to what you can see in the 115 and 161 KV systems. This includes the dynamic aspects of system support.

If we don't do this periodically, we are just fooling ourselves, because our studies will just never mimic reality.

Other things are: Topology -- I found data problems in the case we picked up for this analysis this year that I first discovered in 1992, working in the ECAR region, building base cases. It was the same problem. I fixed it for four years running on all 15 cases that ECAR built.

The problem is still there. What's wrong with this picture? They were just never corrected. Bad modeling, it can really bite you. Next one.

(Slide.)

MR. CUMMINGS: When we started in on the post mortem, time synchronization of the telemetry, and all of the digital fault recorders became a real nightmare. In the earlier stages of the analysis, it was pretty easy. We're looking at minutes in terms of between events.

However, when you get down into milliseconds as you get into the dynamics area, this really needs to be fixed. We've talked about this before in a couple of other outages across the time, and synchronization has to be done at the point of origin, because that's the only way you're going to get them on the same basis.

Another problem we had was inconsistency of data quality and the retention of those data. We found key bus voltages missing from recordings of the system. That makes it really hard to go back and try to backtrace. Next.

(Slide.)

MR. CUMMINGS: Line rating problems: As Tap was just talking about, the methods of calculations, we probably need some bounded parameters. We're not going to let anybody give us a ten foot per second perpendicular wind speed and say, oh, that's okay.

We also have to have some sort of quality control on the ratings. What are the boundary conditions on clearances?

On the thing that I mentioned on the disagreement on ratings, we have to have some method of policing that, some method of transmitting a change, even, in a rating. This has to go between the planing models, the interregional studies, the state estimators and the reliability coordinators. Anybody using these data need to be advised of any line ratings changes. Next one.

(Slide.)

MR. CUMMINGS: You need to know where you are in the system. System data exchange is crucial. You need to know what units are online; you need to know what transmission lines are out of services.

We went into this when looking at the system data exchange that's used by the IDC and used by some security coordinators as input into their security operations, and it disagreed with actual system conditions. There were omissions, errors, and some non-outage elements that were listed as being outage.

That just creates a problem; it creates misunderstandings. Another thing is untimely data entry. There were lines that were out of service for quite some time before they ever were entered into the SDX.

This also is a problem of an incomplete picture.

Not all of the CAs and RAs are entering the data, and we're starting to depend on this.

In the work we're doing with PJM and MISO, we're asking them to update the SDX data on a cyclic basis equivalent to their LMP engine calculations. This is so that we make sure that we keep the IDC in lockstep with their calculations.

Is real-time data needed here? That's the best way to do it. This topology process that we talked about a little earlier, maybe that needs to be what feeds the SDX and the process or until such time as we can ensure that everybody's got the topology process. Next.

(Slide.)

MR. CUMMINGS: Regional and interregional studies: We need to take all outages, including generation, into account when we're looking at things. We need to do more than just N-1 contingencies. Some severe outage scenarios are obviously necessary.

And we need to monitor the entire system, not just regional interfaces. Zonal analysis: If we're just looking at corporate boundaries, we're going to miss the big picture of pockets of the system that regardless of ownership, are going to behave the same way for certain things.

We need to also look at a wider variety of transactions, study the known patterns, analyze the historical trends that are in the tags, and both magnitude and the trends of transactions have to be recognized in a simultaneous nature. Next one.

(Slide.)

MR. CUMMINGS: This is a cut set that we took for the analysis. The orange lines are where we drew the boundaries, and just to look at what was the impact of transactions that day, particularly to look at what was going into the ECAR, this area right in here.

Now, we discounted the flows coming in from this side of the system because we were really interested in what was coming around from the South and the West. Next slide.

(Slide.)

MR. CUMMINGS: And what we see is, from the first of June through the 13th of August, was that we were, indeed, that day having very heavy transactions. They weren't the outer bounds of the transactions, but they certainly were heavy.

So here we are thinking we've got heavy duty transactions, but I think we were also being lulled into a sense of going in the wrong direction. Next slide.

(Slide.)

MR. CUMMINGS: Some of the things you need to think about in terms of simultaneous transfer studies:

These are some of the studies that are done. Paul mentioned the MEN studies. MEN looks at simultaneous transfers and the nomograms.

VEM looks at sensitivity studies for selected transfers; MET only for the Wisconsin, upper Michigan system, but a good one that was just done this past summer is as a prototype was the coordination of summer transmission assessment done by MISO, PJM, TVA, SOCO, AECI, SPP, Entergy.

And it fully looked at simultaneous transfers. Next slide.

(Slide.)

MR. CUMMINGS: This is one of the nomograms from the MEN studies. And these two are the operating points scheduled in actual, and you can see from this nomogram that they're operating within the bounds of the situation for the day.

One thing about this, though; this is not something that's not necessarily immediately at the fingertips or the knowledge base of the individual operators. They don't have enough of the information to actually put this in their hands. Next.

(Slide.)

MR. CUMMINGS: So the situational recognition is important. Where are you? And what units are out? How are you going to deal with your system that's in front of you?

These are all the other problems we've talked about. Some dynamic transfers are not tagged, so you need to understand that those things won't be reflected in something like the IDC and in some security analyses. Next slide.

(Slide.)

MR. CUMMINGS: We did some looking and seeing, because our concern was, we felt that everybody thought there were transactions that were causing the problems on the 14th. Well, it turns out that the tag transactions only played a minimal role and had a limited flow impact.

So here we are thinking that we've got a transactional problem and in reality, what we have is a more localized problem. The main contributors were flows into the overloaded lines based on network loads and generation.

We talked about what you'd have to do in terms of load shedding, 1500 megawatts when you're talking about South Canton Star and 2500 megawatts by the top of the hour in order to get under the system. These are boundary conditions.

So, here we think that we're going to have to go into TLR. If we go looking at trying to do a TLR, and we don't think about doing immediate load shedding, we're going down the wrong path. Next slide.

(Slide.)

MR. CUMMINGS: This gives you an idea of the composition of the elements of what was going on on the lines in particular. Of all the transactions, all the different levels of transactions, you didn't really get any serious relief on South Canton Star until you got out into your native and network loads.

So, if you have this at your fingertips, you know immediately that you've got to go to load shedding, that transactions, going after transactions is going down the wrong path. Next.

(Slide.)

MR. CUMMINGS: So just in summary, some modeling improvements are needed: Load power factor, generation reactive capabilities, improved topology awareness, both from SDX and what's happening in transactions. Those are the things that I see.

MR. CAULEY: Okay. Good job. And the last presenter for Panel D is Frank Macedo of Hydro I, and he is also one of the team leaders in the Planning and Systems Study Team.

MR. MACEDO: Thank you, Gerry, and good afternoon. My fellow panelists have covered a lot of ground, and in order not to repeat very much of what has been said, I'd like to focus on five key issues for consideration:

Next slide.

(Slide.)

MR. MACEDO: There is no substitute for being prepared. I think we've heard that this morning, and we've got to express that. And the best way of making sure that you are prepared is to carry out a full set of sensitivity studies to reflect the operating conditions that are likely to be encountered on the day itself.

N-1 contingencies, assessments of N-1 contingencies forecasted peak loads and known firm transfers is just not enough. These studies should go way beyond that minimum requirement.

Clearly, we ought to look at all the outages; that goes without saying, but equally important is to stress the system, look at loads beyond forecasts, look at different import levels, look at all the transactions, and, in fact, the full range of transactions that might obtain.

Bob talked about load power factors. That's clearly extremely important, but also important is the availability of the distribution capacitor banks. Don't make any assumptions; study the sensitivity of different power factors, particularly in the summer with air conditioning load and the lower power factors that result.

Load representations are extremely important, particularly for voltage stability studies. You need to model to the best that you can, induction model loads and other loads that draw on reactive power. At least look at the sensitivity of those models to the performance of the system.

Finally, you've got to look at conditions on adjacent systems. You can't just focus on your own area; you've got to look at how others might be affecting you, and vice versa.

The second issue is minimum voltage criteria. Voltage magnitudes alone are poor indicators of proximity to voltage collapse. I can't stress that any more than that.

The system may be close to voltage collapse, even if the voltages are near normal. The system should be planned and should be operated so that there is sufficient margin between the normal operating point and the point of collapse.

And the best way to do this is to determine the minimum voltage at key buses on the system. And the best way of doing this is to use the traditional or the accepted methods of PV/QV analyses.

I'm not sure how many people actually do these, but I cannot recommend more strongly that these should be done and these minimum voltages established.

Coming out of those PV/QV analyses would clearly be the minimum reactive reserve requirements that must be maintained in local areas to be able to respond to contingencies. And I stress local areas. It's not good enough to look at the overall footprint of a control area; you've got to look at where the voltage collapse is likely to occur, and then show that the reserves are where you need the reserves.

And I'd recommend that the real-time monitoring of these dynamic reactive reserves should also be considered to ensure that the minimum requirements are met.

And, finally, if these minimums, minimum voltages, minimum reactive requirements, cannot be met, then operating strategies must be developed as a safety net. These obviously include load shedding to ensure that there is sufficient reserve to be able to withstand the next contingency.

The third issue is the one that we talked about this morning, and that is the 30-minute adjustment criteria. I've got a different spin on this.

The planning criteria very clearly says that, you know, after one contingency, you can manually adjust the system to prepare for the next contingency. And the operating policy, too, says that you've got 30 minutes to do that.

What I'm here focusing on is really the measures that are relied upon to achieve the 30-minute adjustment. It's extremely important that those measures are duly considered in the planning timeframe and in the operations planning timeframe, and that these measures are shown to be feasible, and that they are communicated to the operators who are going to actually apply these measures.

Now, if these measures -- if we cannot -- if these measures aren't available and I cannot implement them in 30 minutes, then clearly the system must be operated to the N-2 to be able to withstand N-2 contingencies.

The fourth issue is extreme contingency evaluations. We heard some of this this morning, but I want to stress this: The criteria requires an assessment of system performance for extreme contingencies. In fact, this is Category D of the NERC planning criteria.

Now, these are contingencies beyond the normal, expected criteria, and these are things like multiple outages. These assessments measure the robustness of the system and they help to maintain the state of preparedness to deal effectively with such events.

Greater emphasis must be placed on these assessments to determine the impacts. And equally important, the results of these assessments must be communicated to all affected entities.

The control room operators should know the results of these studies. It's just not sufficient for planners to do these and keep them to themselves. You've got to communicate these to all people who are likely to be affected by it, so that they are prepared.

And, finally -- again, we talked about this this morning -- we must consider safety nets such as under-voltage load-shedding schemes to contain the disturbance to the local area.

Finally, the issue on regional coordination procedures: Each control area must review the results of regional and interregional transfer studies and ensure that these studies or their studies capture the impact of external transfers and conditions on adjacent systems.

Again, these control areas must really communicate any potential adverse impact of these others who are likely to be affected. And, in fact, I'd go further than this and I'd say that there should be a formal peer review process, and, in fact, an approval process to ensure that these systems meet performance.

In NPCC, we do have this process, which is extremely valuable, and that is that each control area carries out these studies, a full range of studies, including extreme contingency studies, and presents the results of these studies to other control areas as part of this review process.

And these other control areas have a chance to ask questions, to suggest further studies, to essentially fully understand the impact that this one control area might have on other control areas. And then they essentially sign off on this and say, yes, you've done some studies, we understand the impacts, great. I would really strongly recommend that this sort of approach be applied much more widely.

And just one final, in passing, if I may. The other panel has talked about real-time monitoring and ratings of lines and so on, and that's all good.

One thing I didn't hear mentioned at all was to do periodic condition surveys of rights of way. You need to know what the clearances are on a right of way, an annual survey of the right of way to determine any obstructions, any limitations on that a right of way. To me, that seems to be absolutely essential. Thank you.

MR. CAULEY: Okay, thank you. Those were very good presentations. We'll start with the panel of investigators, and any comments or questions.

MR. MEYER: I have a question for Mr. Seppa.

MR. CAULEY: That is David Meyer, DOE.

MR. MEYER: I have heard -- perhaps this is anecdotal, but I have heard reference by some people to the concept that as lines heat up, that will generate a natural convection process in the vicinity of the lines so that in that sense, a line is at least to some degree, self-cooling.

And I wanted to see whether you regard that as a realistic assessment, and how significant an effect is it if it is real?

MR. SEPPA: Thank you for the question. You are talking about one of the great urban myths of operations. I have been a party in the working groups, actually, the chairman of the working group that wrote the last IEE thermal rating standard, and also I'm part of the International Standards Writing Task Force to this effect.

And I can guarantee you that the crossover point when you essentially go to natural convection only, that's equivalent to only 0.6 foot per second. And exactly what happens at that range of 0.5, 0.6 or 0.7, that's range. It's not two foot per second. I am horrified at how often I hear operators saying that, well, when you have a cut conductor, you have at least two foot per second. That is absolute nonsense.

MR. CAULEY: Any other questions? Dave Hilt?

MR. HILT: I want to talk just a little bit -- I guess one of the things that I heard was quite a bit of discussion about optimistic power factors and loads, reactive capabilities of plants. I know NERC has some documents talking about voltage and reactive, specifically dating back into the early '90s.

There are data errors in the modeling details and so forth. What strikes me out of that is that I kind of would ask the group and the audience, in particular. It seems that we're not paying enough attention to the details here in terms of when it comes time to do the system modeling.

And having been a old planner and operator and many other things in my day, I'm kind of wondering, where are the system planners today? I know that many companies have rearranged and taken them out. Is this is an issue that we need to take a look at as an industry as a whole?

I think I like Frank's suggestion that we actually have a peer review process on some of the studies, moving forward, such that there is more than just -- first off, it produces some studies, and, secondly, it puts -- again, like we were talking with operations, it puts a second set of eyes on those studies to kind of give us some validity checking.

And I guess I'd be interested in any comments on that.

Secondly, again, we talked about the TLR would not have been effective and that only load shedding would have been. This takes us back to an issue I think we discussed a little bit this morning, talking about local reserves and reserve stacks, those kinds of things in particular areas.

And I was very interested in that and would be interested in hearing what the panel and the audience would think about what tools are needed so that operators would know that they don't have the reactive or the real or reactive capability in a given area to provide the relief or provide the management of the system.

Short of load shedding, I don't know that operators even know that out there today.

MR. CAULEY: Tom, and then we'll take some questions from the audience.

MR. RUSNOV: I'm interested in how you monitor wind speeds associated with a particular transmission line. I guess in Ontario, a typical length of a 500 KV line or even 230 is between 60 miles and 100 miles, if not more.

Some of those go through forested areas where, in fact, they will be shielded, and even if you have wind speeds a the tower top, it's going to be different 40 feet down to make your clearances.

So my view of it is that it's largely a crap shoot. You can have a very localized area with effectively zero wind speeds of very low wind speeds and 50 feet away or 100 feet away, you've got three or four feet per second, five feet per second. How do you deal with this?

MR. SEPPA: Let me respond to this: First of all, you are absolutely correct, you know. Wind speed measurements at a single point do not tell you very much about it. They can give you statistical evidence, but they will not give you real-time evidence of what's happening in the line.

But what you can do is to use the conductor itself as your measuring device, essentially using a conductor as a hot wire. Remember that the local temperatures don't matter; what matters is the average temperature of the conductor between two dead ends, which are a number of miles apart.

So the conductor essentially averages the weather along its length, and that is the whole principle of the so-called real-time monitoring.

MR. RUSNOV: Thank you. I thought there was too much emphasis on the wind speed. That's the answer I like to hear.

MR. CAULEY: Okay, from the audience, any questions of the panel? Back there?

PARTICIPANT: Masur (ph.) (inaudible). Frank and Bob have already listed a lot of issues, and I think there is some suggestion -- have some suggestions or comments that if we -- Frank had stated something about the operational planning. If we can -- my thinking is that we should plan

-- the planning engineers should plan for the reliable operation of the system.

That's like slightly different from what normal load flow analysis -- they cannot cover all the contingencies what we have already seen, so for that, we need some different tools to bring in reliability. I think EPRI -- we don't mention anything about the reliability tools which I think EPRI was developing first (inaudible) probably (inaudible) for whatever reason, and then now they are working on another software.

Maybe they are working on something else, too, or some other company, but we have to bring -- because we can have N-1, N-2, all those contingencies, but still it will only add to the cost. We can try to some extent to reduce the cost, but bringing in the system reliability by using some of the software, because they basically tried to integrate the system planning, take the generation outages, transmission outages, and based on that.

And one of the -- that's my personal experience about the training. It's just my thinking that planning engineers should be during some time, they should be made to sit with the system operator for one week, two weeks, so that they should see how the system is being operated, because they can -- a planning engineer, planning ten or 20 years down the road, cannot visualize all the contingencies, what the system operator is facing day-to-day.

MR. CAULEY: All right, thank you. Ray Kershaw in the back, ITC?

MR. KERSHAW: I want to build a little bit on what he said. If you suddenly go to a more stringent operating criteria. And I don't say we shouldn't do that. I think you have to extend it over to the planning process.

If, for example, ECAR were to suddenly use NPCC criteria for operations, you would be doing a lot more redispatching and TLRs right now. I mean, I'm not saying that you don't do that, you don't go to a more strict operating criteria, but you're going to have to recognize that when you do that, interregional transactions are going to either diminish or you're going to be doing more redispatch, more LMP, and it's going to cost more.

And I don't know how you translate that over to a planning criteria. For example, if you were to ask me, how do you avoid the blackout of August 14th through planning criteria, I'd say build the line.

I mean, that's a pretty simple answer, and I can't tell you right now, how that would have happened in the planning process. But had there been more stringent planning criteria in ECAR, and the same transactions were going on that day, there would be no blackout.

So if you look at what happened in 1965, there was an immense increase. As a matter of fact, we're living off the fat of the increase in the transmission system after the New York blackout. We're still living off of that.

And I'm not suggesting that we go into a building frenzy like we did then, but I think prudent investment and perhaps even ECAR adopting more stringent criteria would be a start.

And we're going to write -- have some written comments on this, some suggestions on how to attack it. It's mostly -- I won't get into it, but we're going to supply some.

MR. CAULEY: Okay, Steve Lee, EPRI.

MR. LEE: I want to clarify something about EPRI. Two software were mentioned, CREAM and (inaudible) by a former speaker. The point is not so much which particular software you use. I think planning is a science and an art.

One of the panelists mentioned the (inaudible) sensitivity analysis, and that's very important. I think it's more important to recognize that planning is the probabelistic process and (inaudible) manufactures uncertain and not captured by the models.

So, it's important to recognize that the probabelistic reliability assessment, as a general term, is what we really should be done. Thank you.

MR. CAULEY: Barry Lawson, NRECA?

MR. LAWSON: I want to address three broader policy issues related to enforcement, compliance, and audits. First, NRECA strongly supports NERC's possible future role as the ERO. This is, of course, assuming that the appropriate legislation is passed.

This would give NERC a much more effective enforcement and compliance capability, especially when compared to their current capabilities. This would have a positive impact on system operations and reliability.

Second issue area: Regardless of whether legislation passes, the industry needs to reevaluate its spending priorities, especially in the context of our restructured and more competitive wholesale energy market. According to a recent EPRI report, capital expenditures for transmission since the early '90s, have been flat. However, O&M expenditures during that same timeframe have been significantly and steadily decreasing.

We have heard here today and in the interim report, where these O&M costs are being cut or at least some of the areas where they are being cut -- personnel, equipment, and EMS maintenance and upgrades, and right of way maintenance for transmission.

While it will not be easy -- and we've danced around this a lot here today -- this trend needs to be reversed. There must be an increased emphasis, monetarily and management-focused on reestablishing adequate and needed O&M budgets.

Finally, there should be in the very near term and periodically thereafter, a thorough and meaningful audit of all control area operators, and that includes approximately a dozen NRECA members, G&T cooperatives, but an audit of all control area operators regarding their compliance with exiting NERC operating policies and planning standards.

And that includes any at the time recently approved and implemented new reliability standards. The results of these audits should be made as widely known as possible.

If peer pressure is the primary tool we have, then we should utilize it. This compliance assessment is critical to understanding how well our industry is doing its job of keeping the lights on. Thank you.

MR. CAULEY: Thank you. Jack Kerr from Dominion.

MR. KERR: I have a recommendation related to Item 3 on the agenda concerning how to ensure ratings accurately reflect actual conditions. I would recommend that transmission line ratings be required to be stated in amps instead of MVA.

And that would eliminate the disconnect we have between the actual voltage component of the MVA measurement and the nominal voltage component of the MVA rating.

MR. CAULEY: Okay, Mike Pennstone, IMO. Are you still with the IMO? No? Hydro I.

MR. PENNSTONE: Hydro I.

MR. CAULEY: Hydro I, I'm sorry, my mistake. Mike Pennstone.

MR. PENNSTONE: No problem. For those of you who aren't familiar with Hydro I, we're one of the licensed transmitters in the Province of Ontario. Our operations are directed by the IMO.

At the outset of this meeting, our gracious hosts asked us for some advice as to what recommendations we should be giving them in terms of moving forward. So in return for your cup of coffee, I'll offer you a few suggestions.

I think that actually a number of these mimic the comments that the previous speaker made. One on standards: We're suggesting that let's not go overboard on developing all kinds of prescriptive standards.

I know it's awfully tempting, but our suggestion would be that you consider two types of standards: One type that is essential for maintaining the reliability -- real-time reliability of bulk power systems, and these standards, I would volunteer, could be prescribed to the industry and not necessarily negotiated by the industry.

I'm prepared to live with those, as long as they are a handful of standards, and I would remind you that Moses did it with ten commandments. I would suggest an equivalent number of standards would be appropriate.

So let's not get into standard dds for developing line ratings, standards for developing vegetation management; let's talk about standards in terms of complying with N-1.

The second set of standards would be objective based. And for those of you who are unfamiliar with that term, that basically says, "here's what you have to accomplish." It doesn't prescribe how you're going to get there.

So again, don't give us standards in terms of the types of tools that we need, the types of state estimators, the number of contingency analyses and all the rest, just give us some high level objective base standards. We'll follow them. Tell us to keep the rights of way clear, don't tell us how many trees to cut down.

The purpose of those standards, unlike the original set, is to basically ensure that we avoid creating adverse or unsatisfactory conditions that are the precursor to a blackout.

Vegetation management was a good example of the August 14 situation -- it was the precursor. If you didn't have nasty vegetation management practices you wouldn't have had the blackout.

Secondly, I think there's a need to establish an environment to ensure that there is a continued diligent adherence to these key standards. January 1 is coming really quickly and it would be a real shame that all of this effort is the industry's equivalent to a new year's resolution.

We do make an awful lot of promises and we're going to do things right so we do do them for a short period of time and then it starts to wane. And somehow, I think this point was made in spades, when you talk about the previous blackouts that we've experienced in North America and the fact that we haven't seemed to learn from those lessons and I would suggest that that environment has two components -- one is a formal, rigorous licensing and comprehensive monitoring of entities that contribute to reliability.

In the Province of Ontario we are a licensed transmitter. That means we have obligations to our regulator. If we don't meet those regulations our license gets pulled.

Now does that mean we take down all our towers and walk away? No. But I am certain that it would have an impact on our senior management.

It is a key consideration when we do our business what those license obligations are and we make sure that we follow them.

The second element I would suggest is that we need incentives to develop and implement reliability, investments and solutions. For some reason they're not there.

Lastly, I have encouraged the industry to try to identify some sets of precursors or measures by which you could identify the potential deterioration in the performance of entities that are responsible for reliability. I think if you read the August 14 report, there was enough suggestions in the practices that were being followed that people should have picked up on it early, come in and asked those responsible to clean up their act.

This is not an unusual practice in our industry. Within Hydro One we do this as a regular basis in terms of managing our safety.

PARTICIPANT: (Inaudible.)

MR. CAULEY: Thank you. You should probably use the mike ahead of time in the front. I think that one lost a battery.

Any other comments from the audience?

Carson Taylor, Bonneville Power Administration?

MR. POWER: I would like to reinforce something that Bob Cummings touched on and that's to increase the comparability and interface between off line planning tools and the state estimator and on line simulation.

For example, it would be very nice and very helpful if you could take a state estimator dump and take it to an off line environment and run dynamic simulations or additional static simulations so every time you have a large generator trip some place in the interconnection, which happens about once a week or so, and that would increase the data quality quite a bit. Thanks.

MR. CAULEY: Anything else from the audience?

(No response.)

Anything else from our panel of investigators? Panel, okay?

All right Frank, one last comment? Frank Macedo, Hydro One.

MR. MACEDO: Thanks Gerry.

Just to follow up on what Carson just mentioned. I think a dump of the state estimator floor plan studies is great but I'd go further than that and suggest that perhaps a dump of disturbances on the system should also be used for training operators, for training personnel.

We do this. We have a capability of doing this ourselves and I sort of emphasize that, if others could do it, it would certainly help. So this would dump all the alarms that come up when you have a disturbance, all the break offs, the whole thing and you could replay that to the operators and see how they respond, of course, when they recognize the situation and what actions do they take?

Thank you.

MR. CAULEY: Okay, Alison? Alison Silverstein?

MS. SILVERSTEIN: This is not a comment but rather a request. A number of the speakers who have talked today and other people whom we have heard from over the course of the investigation have talked about how your organizations have done lessons-learned analyses back home and the wonderful things that you're doing to implement what you have learned from the -- blackout in terms of improving your organization's capabilities and I'm wondering if any of you would be willing to share those with us within the investigation and the Task Force, so if your organizations have prepared reports that you are willing to make public so that we can better understand what you found on your system and how to make it better, I think that those would have great value for us.

If you could share them we'd very much appreciate it. I think you could submit them as part of the same comment process that we're receiving -- other comments.

So thanks in advance and hope you send us lots.

MR. CAULEY: Okay, we have one more panel and it's a very important one, on protection and controls and how we keep blackouts and disturbances in the future from spreading as widely as this one did.

So we'll come back in fifteen minutes, at 3:15 p.m. and we'll conclude with our final panel.

And I just want to make sure I have the presentations of all the final panelists. Check with me if you don't mind.

(A brief recess was taken.)

(Back on the record.)

MR. CAULEY: (Tape gap) in terms of generation and transmission performance but I think more importantly, going ahead, what can we do to better protect the system and better controls to ensure that, if we do have a major disturbance, how do we inhibit the progress of the blackouts so we don't have a wide area cascade and we can contain it into a smaller area.

And we'll start with Carson Taylor, Bonneville Power Administration.

MR. TAYLOR: I'll stand up and waive my hands -- next slide.

(Slide.)

I'm in the middle, I guess, in this cartoon.

Next.

(Slide.)

What I want to talk about on the next two slides, compliance with NERC planning standards which I think is a fairly good description of industry best practices and we really need to start to better enforce them.

On the voltage load shedding, zone free relays has already been mentioned a few times and another recommendation is prioritized control and protection improvements both at generators -- probably mainly at generators, and also at transmission.

Other things I'll talk about is coordinated voltage control design, some ideas on better voltage control and advanced form of capacitor bank design, special protection systems and wide area measurement systems and wide area control systems, automated direct load control or demand side management and the main message is what we need is defense in depth or multiple layers of defense.

We talked a lot about control center improvements and this panel is about improvements in the control and protection.

NERC planning standards, section two and three, deal with modeling and control and protection.

Better off to read here rather than turning -- it was specifically developed following the 1996 blackouts in the western interconnection and approved by the NERC board of trustees in 1997.

That's six years ago now so industry has had six years to digest them and try to comply with them. As most of you know that includes standards, measurements, guides and later development of compliance templates.

There's some enforcement by NERC at the NERC level of the regional consult documents such as a plan for restoration by NPCC for example. It doesn't go into too much detail but at least an audit that these documents and plans exist. Individual regions can do further enforcement.

I would say WCC in particular has been proactive in at least partial enforcement of these standards. There's a reliability management system that is subscribed to by the major utilities, I think almost all the major utilities, and they in turn enforce them, enforce standards with their interconnected generator companies.

For example, in the reliability management system there is a requirement that all generators operate in automatic voltage control mode -- and we do enforce that with our generation companies. It's a struggle sometimes but we're monitoring them.

Generator testing has been a major program in WCC also. We spent many millions of dollars on this. Many utilities have complied and a few haven't.

Next slide.

(Slide.)

I'll just list a few of the most interesting standards here. Synchronized condensers operate in automatic voltage control mode. Another standard that generators shall maintain, network voltage of reactor power output -- as required by the transmission system operator.

Next.

(Slide.)

A guide that generators and turbines shall be designed and operated so there is additional reactive power capability that can be used during disturbances. There's a standard that voltage regulator controls and limit functions shall be coordinated with the generator capabilities and the protective relays.

Next.

(Slide.)

There's a standard on generator testing that I mentioned. This has not been enforced and WCC has been probably the most active in this area.

Also there's a guide, not a real strong statement unfortunately, about zone free relays and the problem with them operating on a combination of overload and low voltage. Basically in my opinion relay should operate for short circuits and not for overload.

Next.

(Slide.)

On the voltage load shedding as has been mentioned quite a few times already, controls have been installed by many companies, Ontario Hydro for example, was mentioned and they put in a very nice scheme in the Ottawa area back in the 1980s. It also included blocking of tap changing on power delivery transformers coordinated under voltage load shedding of capacitor bank switching and tap changer blocking.

TVA put in a scheme, I think, in the 1980s, in our load area which would have a voltage collapse with loss of a 500 kV transformer. At Bonneville and Northwest Utilities put in schemes in the early 1990s in Seattle and then later in the Portland area.

In many locations this is really needed as a compliment to under frequency load shedding. Sometimes you need one and sometimes you need both or you need the other.

There's a few items mentioned but going back to the bottom item, it's possible to replace the existing under frequency load shedding relay with a relay, a new digital relay, that does both under frequency load shedding and under voltage load shedding and you need the same trip circuits so it's a lower cost.

The thing that's important is that the measurement must come from the transmission side or the unregulated side, of an LTC bulk power delivery transformer.

You want to mention all three phases. All should be depressed so you don't operate for a single phase fault. Settings are generally 8 to 10 percent below the voltage during heavy load which shifts from normal.

If you need better than this you might want to go to a centralized scheme that would take additional measurements such as generator reactive power output of generators or remaining reactive power reserves.

Time delay should be fast in the -- around one second in summertime cases where you have a lot of air conditioning load. This was the case in the TVA insulation.

Next.

(Slide.)

This has been a pet topic of mine since about 1968 when I took a protective relaying course from Eric Gross at RPI. He was involved in the 1965 blackout investigation and he preached to us that relays operate for short circuits not for overloads and back in 1970 I was able to get EPA people to eliminate use of zone free relays which is something I was proud of and surprised since I was a young engineer at the time.

In most cases for main grid EHB transmission and even 230 kV you have redundant relays. Zone free is sort of a back up to a back up for very rarely occurring multi phased faults not involving ground. It's not a proper way to detect overload and it's not a proper way to detect out of step conditions.

If it is needed you should look at either blinders or replacement of a digital relay that you can restrict the operation in the load area. This again would be one area that perhaps for prioritized control and protection improvements, which is the next topic.

Modern relays are much more reliable and higher performance. It's something you can do fast and is very different from building a transmission line which may take many years to get approvals and money and so on.

For example, generators, many of the older plants have 1960 vintage voltage regulators and the new digital ones are much better. For example, overexcitation problems, it's a smooth, almost bumpless transfer and you can automatically go back and forth between fuel current control and automatic voltage regulation.

In some cases you might want to replace the whole excitation equipment including the exciter. There may be substation improvements such as change of bus arrangements and so on, that may also be desired.

Digital control and protections have better facilities for built in monitoring which is very nice in disturbance recreation and they should be treated just like building a transmission line going to the right base so that utilities have a financial incentive to pay back.

This a list of the four failures in the Washington area interconnection and I want to just highlight the generation loss. Much of this was unnecessary and undesirable.

For example, at the August 10, there was 175 units with undesirable tripping. Most of them are undesirable or unnecessary.

Next.

(Slide.)

Generators in no danger of damage have tripped during cascade outages for a very long list of reasons there. MOst of them are electrical which means that it's easy for us electrical engineers to improve.

The last one, boiler problems, is maybe more tricky but, with digital boiler controls, it's much more reliable in cases where generators are tripped because of boiler problems, 15 or 20 minutes after the transience.

Next.

(Slide.)

This is an example of the August 10th disturbance and there was an island formed in Northern California by uncontrolled islanding. Initially this is a point of the islanding and frequency excursion, under frequency load shedding worked just like it was supposed to do, a little bit of overtripping and we came back to about 50.5, about one percent over frequency. Also overvoltage because of the load tripping and the unloading of transmission of the inner tie lines.

And everything came back in a couple minutes but then units started tripping, two plants here are shown.

About three minutes after the disturbance and after the successful under frequency load shedding and the reasons are volts per Hertz and loss of excitation and a few of the other things on the list in the previous slide.

They did some additional load shedding and finally recovered to about 59.5 and it took them I think about an hour and a half before they were able to get up to 60 Hertz to resynchronize with the Northwest.

So everything would have been much better if these power plants were not tripped off line for these, I think unnecessary, reasons with better control and protection.

MR. CAULEY: (Inaudible.)

MR. TAYLOR: I'm not done but, okay, I'll keep going fast.

I think there's a lot of things we can do with improved voltage control. The basic idea is that transmission level shunt capacitors should work in conjunction with generators and stator compensators to keep reactive power reserve on generators and also our line drop compensation or high side voltage control, can make the generator voltage control much more effective.

And that should be done on a much more uniform basis that all generators should have coordinated voltage control method. Lots of capacitor banks at BPA.

Next.

(Slide.)

This is a field test we did of advanced high side voltage control. We switched a capacitor bank off and the generator response is shown here, very much better than standard terminal voltage control.

Another thing we've done at Bonneville is what we call CABS or capacitor bank shorting, and to compensate for the unstable behavior of a capacitor bank, output goes away when you need it most, and so we're working with a denominator.

Here's a picture of it where we short part of the capacitor bank and we get kind of like a more static bar compensator, boosted output during low voltage.

Next.

(Slide.)

Insulation of BPA, that was a retrofit on a 230 kV 168 megabar bank.

Next.

(Slide.)

On a modern fuseless bank, this is a 460/691 megabar design from an EPRI study that G-E did. TVA by the way is installing some of these schemes.

Next.

(Slide.)

As far as special protection systems, I would recommend that you put the money first into basic control and protection upgrades. Control separation is difficult and a mess. It can be done but it might be solving the August 14 problem instead of the next problem.

Out of step relaying involves impedance relays and you really need to carefully design any kind of control separation scheme.

Next.

(Slide.)

Wide area measurement systems. This is something with like 30 times per second data rate or 60 times per second data rate. We have it in the West and the AEP, TVA, Entergy and New York and maybe some other utilities are looking at it in the East.

Next.

(Slide.)

As far as centralized wide area control system, BPA is putting in a scheme called PLAX. Basically this is a voltage measurements and a combination of voltage measurements and generator reactor power measurements and it's a flexible platform that can be used for capacitor bank switching and load tripping and direct load control.

Next.

(Slide.)

Next.

(Slide.)

Next.

(Slide.)

That view, real time control is what we're using.

Next.

(Slide.)

Measurements are at a number of locations all within the Northwest using BPA fiber optic communications.

Next.

(Slide.)

Direct load control for stability. This is something that we've been promoting through a (inaudible) task force. Jeff Davo was actually the head of it or was the head of it. The idea is to go piggyback on the demand side management or direct load control put in for other reasons but to try to shed load fast and painlessly and a lot of schemes a lot of capabilities of it existing such as using a simple pager technology. You can get air conditioners off within 10 seconds or so. PEPCO for example does this or did it and I would suggest maybe automated activation rather than manual activation.

And I think that's it so sorry I went over.

MR. CAULEY: Thank you Carson. I had to twist Carson's arm to get him to fly all the way across the country so I feel bad about moving him along but I appreciate your being here, Carson.

Next presenter is Phil Tatro from National Grid.

MR. TATRO: Thank you.

I'd like to talk about the application of protection systems within NPCC and how it relates to the questions that have been raised. There's quite a few very good questions, probably too many to cover in seven minutes, so what I would like to do is just draw on and group some of the questions together and draw up some highlights.

I think a lot of these questions, the answers are still under investigation but, by drawing out some of the critical considerations that need to be evaluated in answering these questions, we can help to make sure that, as the investigations go along and that the questions are answered, that we've got a thorough analysis behind the answers.

I guess I'd also point out that I think the answers probably will not be one size fits all but one may be correct in one system and may not work in another system.

Moving on, just briefly I have taken a few excerpts from our MPCC book power system protection criteria and right up front we state the objectives and you can see where the objectives fit right in with the idea of minimizing the propagation of outages, limit the severity and extent of the system disturbance and then, if you do have a system disturbance, you want to be able to have a timely restoration so you want to limit possible damage to system equipment so you can put the system back together.

And our guidance is from the bulk power protection criteria and maintenance criteria for bulk power system protection. These tend to be, these give us our guidance, they're functional criteria, they're not prescriptive, but they are very comprehensive and part of the processes that we go through in MPCC, there's other procedural documents also that govern the peer review process that we have when protection systems are added to the bulk power system, so that all the members of MPCC review those and I think it yields a better overall product.

One of the, I guess it's possibly unique to MPCC is that we have a functional definition of the bulk power system so where we apply our bulk power system criteria is based on the results of system studies.

I know in New England we have a 23 kV bus where a single protection element failure could cause an impact outside the local area. Conversely we have a 345 kV radio line where an end of line fault, there's no problem with delayed clearing.

So by having this functional definition and integrating system studies into the design of the bulk power system protection facilities, we are able to focus our attention to the areas of the system that require the greatest level of protection reliability.

Just a few excerpts from our criteria. There's many others that we factor into the design but a couple of the key ones are that all bulk power system facilities are protected by two protection groups that are entirely independent of each other and both capable of providing the required protection function.

We annunciate or monitor critical system functions, guard signals, cut out switches. There's monitoring of the cut out switch to make sure that, when maintenance is done, that systems are laced back in service. Trip circuit integrity -- and I think that probably one thing that's common to all protection systems is that a significant number fault operations occur during testing so we in our maintenance criteria we stress that the test procedures have to be consistent with the design so that we don't compromise the integrity of the protection systems.

Now everything I've talked about so far pertains to how we make sure that a protection system failure does not cause a widespread area outage. It think the heart of the question that was put before the panel was 'can the relay systems halt or arrest a cascading outage and prevent a cascading outage and maintain integrity of as much of the system as possible -- and I think the answer is they certainly can.

But the design of the protection system requires information from system studies about where the system is likely to break up so that if you were likely to employ out of step blocking, out of step tripping, that you know you're doing it in the right locations and that, this is one of the areas that I think might vary for different parts of the interconnection.

I think Carson pointed out in a very tightly meshed system it's going to be more difficult to identify where the system is going to break up.

And in MPCC to date we have not employed out of step tripping and blocking for this reason.

One of the other things that we stress in our criteria is that effective system protection design requires coordination among all of the engineering disciplines. Planning and engineering, system studies, have to all be factored into the protection system design so that protection systems operate fast enough to be dependable and have adequate margin to operate in a secure state and we do call out in our criteria that tripping of relays should not occur for stable power swings and that protection system settings should not constitute a loading limitation.

A few of the other specific questions, one had to do with underfrequency load shedding. Coincidentally MPCC was in the process of reviewing our frequency load shedding system prior to the blackout. We've gone ahead with trying to implement some of the findings of the study but at the same time we're waiting for additional analysis from the blackout to decide whether any additional modifications are appropriate.

Just a few of the high level concepts, the program has to be designed for the expected magnitude of generation load on balance. We use a maximum of 25 percent in MPCC, 25 percent generation deficiency.

The load shedding must be distributed so it's homogeneously applied across the system. This is especially important in a mesh network where you're not certain where the system's going to break apart. You want to make sure that you don't end up with all the load shedding be shed in one island and not in another island.

A significant issue with coordinating generator tripping with load shedding and the other thing is that the load shedding scheme is in place for conditions where the system governing response is inadequate to recover the system frequency.

The load shedding scheme is there to bring that mismatch back to a point that's close enough that the system governing response can recover the frequency.

So we view that the primary function of the load shedding scheme is to arrest the frequency decay. You still need the system governing response to recover the system frequency and I think that's a very important issue that I know it's in MPCC where we're initiating a lot more investigation into this area.

Considerations for special protection systems, not surprisingly very soon after August 14, a lot of people started proposing that maybe we need more special protection systems to help prevent the widespread propagation of a system event such as that one and I think everyone who has endorsed that idea someone else has probably identified that inadvertent operation of SPSs could take the system in exactly the opposite direction.

So I think the key is that you need to be judicious about where and when you want to apply an SPS and I think the first bullet is a direct quote -- if not a direct quote very close to it, from our 8/11 document, special protection system criteria, which you just can't emphasize enough that special protection system design requires coordination among system planning design maintenance and the protection groups, not only for the design but throughout the life of the SPS where the system conditions change. You want to make sure that the SPS is still going to be dependable and secure.

And finally there were some questions about dynamic recordings and analysis of system events. I brought some of the documents and procedures that we have in place. One is for collection of real time data for an aerodynamic analysis and that actually incorporates some of our neighbors also in MAC and ECAR that we collect data, have the procedure to receive data from them also.

And then the different task forces, task force and system protection reviews of disturbances, but also task force system studies has their own review process and we also review protection systems as operations.

Time synchronization issues -- I wanted to get it up here. I figured by now I'd be running out of time so I didn't put too much up here. But I think what I'd really like to say about this is it goes far beyond just simply having synchronization on the device.

If a device, if a fault recorder for example doesn't trigger then it doesn't matter that it's synchronized. It's not producing a time stamp for the event. And then the other one is that we have identified some devices that have synchronization but, due to some mechanical problem, the antenna, you know, has been knocked over in a snowstorm or something and so when people are thinking ahead to what issues need to be addressed in putting a standard together, I think monitoring of the synchronization signal to make sure the device is locked in is important.

In summary I think really the -- I can't emphasize enough that the effective protection system design, it's a multi discipline approach and I think that many of the questions that have been put before the panel will require some more input from some of the ongoing system studies and I hope that this discussion will help to focus those studies to either focus on some of the key things that need to be considered in the studies.

Thank you.

MR. CAULEY: Okay, the third panelist is Chris Rousseau who is going to talk about frequency issues.

MR. ROUSSEAU: Good afternoon. My name is Chris Rousseau from Rousseau & Asc. and OSI Soft.

I apologize that, for this presentation, the lack of a PowerPoint we were a late addition to the schedule so unfortunately you'll probably need to squint to see what I have here.

I'd like to make a brief presentation about the results of an analysis that Dr. Chuck Wells and I did based on the data. In the past we've worked together analyzing several outages and in looking at the August 14 one we noticed some similarities to some prior outages, most notably the Malaysian outage in what, 1995, I believe, and the Rush Island issue in 1992.

Characteristic of both of those outages or blackouts was low carrier frequency oscillations and we had a hunch that perhaps we might look for the same pattern during the August 14 blackout.

What we did was we took the data that was provided by NERC and we later conducted our analysis using data that was donated to us by a member utility from the Midwest and we performed Fourier transforms on the data starting from approximately the time the Eastlake generator tripped.

What we found was, this outage much like the Malaysian and Rush Island outages, showed characteristics of long carried oscillations that are not present -- under nominal system conditions.

If you take a look at the -- actually, if you could scroll down please? That's the one right there.

I'm assuming that most people are familiar with Fourier transforms but for those who are not perhaps familiar with the methodology, it is a way of identifying what I term "subfrequency" -- pattern data.

In other words, typically the normal frequency of the bridge of the 60 cycles per second -- this helps identify longer period oscillations, in this case, oscillations from 19 through 77 minutes that may indicate sort of a longer period system instability.

What we found and if you look at this graph here you will note that the yellow lines indicate both the -- normal distribution of an in-control -- let me move this microphone just a bit -- the normal distribution for frequency error for an in-control process and so there is this sort of nominal exponential error and plotted on that chart you will see the frequency distribution for the August 14 data and, in particular, the balloons there, you will notice that there are at least three distinct peaks and one, the fourth peak there, at 11.3 minutes, we couldn't decide whether that was a real peak or not, but you will notice at least several distinct peaks that do not appear under normal system conditions.

Comparing this to nominal system data and if you will scroll down a little bit you will find it -- this in particular is from the Western interconnection -- you don't see quite the same pattern of data. And in fact when we did a moving window Fourier transform of the data, the point at which the Eastlake generator tripped, we noticed that the amplitude of these peaks increased showing a problem that may have in fact -- and in fact was, increasing in scale.

What we've been working to do over the last couple of months is work with some utilities and ISOs and in fact we've implemented real time Fourier transform methodologies based on some of the incoming data from these and fortunately -- I suppose is the appropriate term, fortunately we have not seen any of the same characteristics yet.

While it is probably not accurate to say that one could have deduced the magnitude of the problem based solely upon the frequency data, back casting our algorithms and back casting Fourier transforms over the frequency data did indicate a situation that was anomalous given the normal frequency, normal system characteristics of the Eastern interconnection.

So we're going to continue the methodology both with ISOs in the Western and Eastern interconnections and see if this can possibly be used as a tool in the future to identify unusual system conditions.

Thanks very much.

MS. SILVERSTEIN: Sir, before you sit down would you be good enough to tell us not just that this is anomalous but what it means? And what is the implication of this?

MR. ROUSSEAU: Right. You may have noticed that I pointedly avoided what it means.

MS. SILVERSTEIN: I figured that was because you were a consultant but --

(Laughter.)

MR. ROUSSEAU: Right. It's difficult to say exactly what it means. It's difficult to look at this data and say that, given the pattern of frequency instability like we saw on August 14 that a blackout of the magnitude we had would have occurred.

What we can say is that this type of frequency instability bore similar characteristics to other outages of this scale in the past. And these frequency peaks that we saw are not consistent with normal Eastern and Western interconnection data.

So by themselves looking only at the peaks one may not be able to deduce that there are significant frequency problems. But in back casting the data, in back testing the algorithm rather and looking at the data, if one were to be looking at the data in real time one might have deduced that there were unusual system conditions and we tested this against both the August 14 blackout and other blackouts in the past.

And our -- you caught me on the fact that I pointedly avoided saying what it meant. But what I am suggesting is that it may be a useful tool for identifying periods of instability in the future.

One of the problems during August 14 in fact was that I think a lot of the participants or victims of the blackout did not quite know the extent nor did they know the magnitude of the problems that were occurring and so looking at this data may have given them some indication of what was happening.

MS. SILVERSTEIN: Okay but let me check a couple more things with you. You cited two other major outages that had this similar frequency characteristic. Have you looked at other outages and found that similar frequency anomalies did or did not occur? Beyond these two?

MR. ROUSSEAU: We have only looked at -- closely examined those two because those are the only two other outages for which we have -- data of sufficient quality. We're planning on looking at other outages of this scale and scope in the future.

MS. SILVERSTEIN: Okay so what you're telling us is this is, there is a correlation between these three outages as a function of the frequency anomaly but you are not venturing whether there is a causal relationship, is that correct?

MR. ROUSSEAU: No. In fact I don't think it is a causal relationship. I think it is, I think the frequency instabilities were a, certainly not a cause of the problems that occur but -- an indication of their extent and magnitude.

MS. SILVERSTEIN: Okay so you're offering this as something we should pay attention to in the future to see if it is a useful marker?

MR. ROUSSEAU: That is a fair way to put it -- yes. That's a good way of putting it succinctly. Something that may be useful to pay attention to in the future.

MR. RUSNOR: I think our mandate is to see that you're going to wait a long, long time before you get another experience with it.

(Laughter.)

MR. ROUSSEAU: As I said, we haven't seen -- frequency instability of this type since August 14 and with any luck we won't see it any time soon. Thank you.

MR. CAULEY: Thank you.

The fourth panelist is Tom Wiedman who is the current investigation team leader for the transmission area. Bob Stewart of PG&E did a wonderful job then he had a long, planned vacation, so that's where he's probably still at.

Tom Wiedman is from ConEd and he's been in his stead for the last few weeks.

MR. WIEDMAN: Thank you Gerry.

My talk is going to be kind of a summary of what we've done so far and some lessons learned followed by some recommendations.

Go ahead Gerry.

(Slide.)

This slide is organized by time frame from 15:05 hours Eastern Daylight Time to 16:06. It's also organized by the way the lines tripped out and in blue I identify the lines. I also identify that the lines tripped out primarily by ground faults.

So one could deduce that these lines had been tripping by tree contact based on the signature of the faults.

The final two events leading out of this time frame were a product of the first four events and that is the outage of a substation which was caused by relay actuation in a breaker failure and finally the first line that tripped due to non fault conditions.

And this has been the doorway which opens up into the future operations throughout the time period leading up to the blackout.

As the cascade moved west and north, 138 kV lines and 69 kV lines in these stars, South Canton areas, were tripping on heavy power flow. We then moved into a tripping of a major 345 kV transmission line and there was kind of a combination of a ground fault initially and then heavy power flow on the automatic reclose.

That brought on another trip of 138 line and finally the last trip before things really accelerated and that was the East Lima to Fostoria Central, a 345 kV line. This line also tripped on heavy power flow and by "heavy power flow" what I mean is, I'm strictly staying -- staying away from saying that it exceeded emergency ratings. All I will say is that it was at a flow at or above its emergency rating and that the relays intended to trip for fault currents actually operated for power flows.

The cascade then moved into Michigan. The time frame compressed from 16:09 to 16:10:40, just a minute and 40 seconds and, in that time frame, it was characterized by major interruptions between the Western side and Eastern side of Michigan. These trips were started off with a trip on one end of a line, the Argenta end, for both Argenta - Battle Creek and Argenta - Tompkin, on a single ended trip for a zone three relay, a back up relay.

The system condition at the time was characterized by overloads, very low voltage and phase angles that were widening, phase angles that were measured by current legs voltage or as measured between source and synch bus as measured through the digital fault recorders.

It is important to say that, at this point, there was no dynamic instability as we would initially think there would have been. It was quite interesting to see that the angles were widening but it wasn't at a rate that one could easily say how the system is in an unstable condition.

More 138 kV lines tripped in the Argenta area and then finally the Hampton - Pontiac and Bedford - Jewell lines tripped, which were slightly north and a little bit west of the Detroit area. These lines were also characterized by tripping due to overloads, low voltage and widening angles, but again, not instability and it was at this incident time that we theorize that synchronism was then lost in the Michigan area around Detroit.

Okay Gerry.

(Slide.)

We then turned our attention to looking at the other side of the Cleveland area corresponding to the next trip which was a transmission line between Perry, Ashtabula and Erie West. This line was a little more unique than the other lines in that the true, the Perry substation had low voltage but there was actually heavy reactive flow toward the East while there was active power flow going towards the west to feed the Cleveland area.

So again this was slightly different than the other trips.

Our next activity is to work on the phase two report, which is, would be a NERC input into the Canadian - U.S. task force, as will other inputs be. Our major focus is to work with the sequence of events team and the root cause team, the planning and dynamics team to analyze what this system performance really was during these events and to try to model the actual events so that we can learn something and apply that to possibly new technology and lessons learned.

We're intending to evaluate transmission line readings, impacts on this cascade, we're certainly planning to incorporate the comments from this public forum and other public fora, the NERC steering committees and the NERC standing committees, and then to seek overall endorsement on recommendations that we all come up with.

What have we learned so far? As I said before, line trips due to faults -- trim trees or preferably remove the trees from the EHV right of way.

Second of all, lines tripped due to low voltage. Consider the use of undervoltage load shedding in recognizing that it is a local solution but when taken in total may serve to mitigate or slow down future cascades and these undervoltage load shedding schemes should be developed with standard philosophy in mind much the same as what Carson had presented to us.

Line trips due to heavy power flow, we've evaluate the need for zone three time delay tripping on EHV lines -- the lesson I learned here is the need to develop settings criteria that is known commonly by the planners, by the operators and by the relay setters, and what is the primary reason for an element to reach well beyond its protected line and what can we do to bring that setting a little less far out into the transmission system?

To tell you what -- to show you what I mean by that is just a simple geometry lesson -- for those of you who are unaware of how transmission line relays generally work and how they can be sensitive to load, the circle represents an area on a plane. It's called the impedance plane. It's a way of depicting the way an impedance relay will work.

And if a quantity of voltage divided by current, which is what the relay detects, gets inside that circle it's going to trip. And voltage divided by current can be -- fault current but it also could easily be load current and just using a mathematical manipulation, that number can also be considered as the kD(squared) that the relay C is divided by the MDA or the combination of reactive and real power -- the square root of that -- and also there's an angle associated with that which is the arc tangent of the reactive power divided by the active power.

And the three circles are there to indicate that that is a moving point especially in situations like this where the system is actually cascading.

Next slide.

(Slide.)

This is a little more of a combination of circles that I stole out of the I triple EEE power system relay committee document on relay "laudability" they call it. And just to demonstrate that there's actually several regions of power flow that can impinge on or get close to the tripping of protected relays.

In the far right hand quadrant you can see when power is out of the relay -- that's active power -- and active bars are flowing out of the relay, that can impinge on the relay and cause it to trip.

But equally so, if power is flowing into the relay and reactive power is flowing out of the relay, which is in the upper left hand quadrant, that can also cause the relay to trip and remembering that equation which was nothing more than V over I, voltage over current, one can see how a load flow can actually get inside this relay characteristic and cause the relay to trip.

So what can we do to, given these relay characteristics, what can we do to diminish this probability? I'd like to go to the slide here which is again another geometry lesson but it's simply two right angle triangles imposed within a circle and, if I cut the one side of the triangle in half, I would cut the other side of the triangle in half. That's all it is.

The one triangle inscribed within that circle is the diameter of the circle and that in fact is the reach of the relay in the fault angle in the fault direction and that would be what the relay would see if the voltage divided by current was actually a fault whereas in the lower or leg of the transformer that is inscribed on the lowest part of that circle there, cutting that in half is more like what you would see in that load angle or that load ratio of the power system and by cutting that leg in half that has the same effect as actually doubling the amount of load current that that transmission line can see before it operates for load current.

So the focus then should then be on those transmission line relays that have very sensitive settings, what can we do to bring those settings more in line with protecting only that line, thereby diminishing its sensitivity to load current.

Next.

(Slide.)

Some additional lessons learned and which required additional data yet the underfrequency load shedding relays, coordinating with the underfrequency tripping of generation. Right now we have many underfrequency trips of generators that after the 1965 blackout probably none of that occurred. So we need to make sure that our underfrequency load shedding program does indeed coordinate with the underfrequency tripping of generators.

I'd like to emphasize independent NERC and regional compliance standards and measures for protection systems. Let's make sure we all know what each one of us is doing with regards to protection and measure that.

Develop standards on reporting of disturbances including prescribed common reporting format -- one of the problems we had not only with time synchronization was the very different ways that digital devices captured the data and then tried to bring all that data into one common format. There's a standard for that and I triple EEE standard, but I think that needs some work on it to definitely bring it into an operating arena, analysis arena, and I believe that effort should be going on not right after a blackout but just as a constant process -- there needs to be that ability to bring that data in and look at it in rapid time not only for the transmission owners but for the regional transmission operators as well, the reliability coordinators.

Coordinate relay tripping with line emergency capability and assure for conscribed, proper automatic operation of generator excitation systems, again as Carson had alluded to.

Finally we would capture this as the following recommendations which I would sure like to get your comments on and that is NERC, its regional reliability coordinators need to develop protective performance criteria and compliance audit standards to install undervoltage load shedding throughout the Eastern interconnection to evaluate line reading methodologies consistently possibly using the same equations, certainly the same methodology -- identify likely break points in the Eastern interconnection -- as the system cascades, how likely is it that the break points are the same in every event or is there a new tool that needs to be developed that will identify break points as the system dispatch and line outages change?

Develop disturbance analysis methodology across the Eastern interconnection -- and finally, insist on voltage support requirements for generators.

That's it. Thanks Gerry.

MR. CAULEY: I'm giving these guys a little more leeway on time because they're last.

So the final speaker of the day is Gary Bullock of TVA and he's heading up the generation performance team.

MR. BULLOCK: Thank you Gerry. Good evening.

It's actually almost evening is it not? It's been a long day. The party got started at about 8:00 a.m. and if you're like me, that's been a good long, hard day of it.

I am from the South, the Tennessee Valley Authority is my employer and about a week or so after the event that occurred, at my boss's instruction with the pleasure of NERC I joined the group and participated in the fact finding teams that got started collecting some of this data. It was an entering perspective on my part and then I later joined the generation team effort as we concentrated on the generation performance control aspects of this event, but I was also associated with the other teams as everybody was working in conjunction.

I spent a lot of time with a lot of very talented, knowledgeable people both on the NERC staff, the participants from FERC, as well as other industry and utility volunteers, including some key manufacturers that were on my team and on other teams and it was greatly appreciated.

It's been a long but very important day for me as I have been most interested in hearing some of the comments and insight that your different perspectives have offered. They have given me a fresh look and I hope you've had a few opportunities to be challenged as well about the way you think.

The data that I'm going to present is not so much recommendations although I have a few of those that I would like to leave you with at least in thought.

But to give you a flavor of some of the interesting data that I have seen as we went through some of this information, some weird and wonderful stuff as far as opportunity to see it but -- challenging in terms of what do we do with that in expectation for the future?

In summary though from a generation perspective, I will point out these six things and then refer to some others. The generation outage in this case did not initiate the cascading event.

Now the second point is also true though -- there were unit trips in the Cleveland area and in the vicinities -- yes, they did contribute to the conditions leading up to these events.

During the conclusion of the cascade and, as David pointed out earlier this morning as if you could remember from back then -- this time frame for this event occurred, at the very conclusion of this cascade was measured in seconds instead of in minutes and that happened very fast.

At the conclusion the generation seemed to trip into three different categories or buckets of classes of failure. First of all the excitation systems were failing in their overload conditions after being stressed from earlier in the day or from the conditions of the moment at the times of separation from the different islands as this thing was breaking apart.

Second, plant control systems took action and/or failed and resulted in the generation units tripping, for those reasons as they became sensitized to some things that were going on, and third is a consequence of the system simply breaking apart and the units being left islanded with no load reserve and disconnected from the load or tremendously overwhelmed with too much load and frequencies collapsing.

In addition to that, it is somewhat of a surprise as we've walked in looking at some of this information. There were some prolonged out of step conditions on the system that were quite evident.

My conclusion, or at least my perspective, is that generation performance may have expanded the boundaries of the result of this blackout but I must classify "may."

This is almost like trying to put a pinball machine and know where that little metal ball is going to bounce next. It's just almost impossible as this thing ended in a few seconds of collapse -- to know for certain that one thing or the other could have changed the consequences and the boundaries. But it's possible.

And I'll point out some of those.

Today this is a bit of a surprise as little damage has been discovered as a result of this event. Now that's good news -- although there may be some bad news hanging in the wings as time progresses and things have been stressed.

The first thing that I will point out related to the idea that excitation systems were overloaded, everyone is understanding that there was a unit that came out very much earlier in the day. That's the little blue box up there close to the light. You see that it's in the vicinity of Cleveland -- that is Eastlake Five.

Go to the next chart and you will find that this indicates the performance of that unit through out the morning and at the moment of very trip you can see that the purple curve right there at the top where the reactive output of the unit had just increased -- that was an operator action because of the times of stress, the voltage was fallen at the time and he was taking action at, instruction from, the control center to try to support voltage more.

And then the total collapse of the reactive output as an excitation trip -- not trip but delimiter, had taken place and tripped off of automatic to manual mode and then, within four and a half minutes of the operators trying to restore that reactive support, the unit trips completely off as the excitation system simply fails.

Now, from this point on through the day as, without this unit, of course, there is even more stress on the -- trying to maintain the voltage in the area -- and there are other units that are also stressed and they go through this same sequence of tripping the excitation system but not completely off. They then cool off and they ramp back up and they'll only be tripped again and there's indication of all of that.

All this points to the fact that there was no margin in the area where the generators were trying to hold the voltage up. They were operating at their maximum.

As the cascade actually starts to happen, this not obvious from the chart in terms of the color that I chose -- red, and red is a poor choice for the little circles, but you see a point here at Avon Lake and there's some Burker units and there's a Morgan unit that is an IPP in the central part -- all of these transpired within a short time period right before the central lines right here began to operate, trip off, that Tom had referred to a little bit earlier ago.

And they came off for different varied reasons. It wasn't one common mode of failure although they were related to performance of the units under stress of local pitched conditions in an area that had already been compromised by lack of sufficient transmission and local generation to support the voltages in that area.

The Avon Lake unit for example, five seconds before, and this kind of alludes to a comment made earlier about the need for collecting data and have systems to collect data for validation after a fact but we've had to piece some of this together -- I have a DFR shot from five seconds before Avon Lake tripping -- it shows the local voltages around 76 percent and had been that way for several seconds to a minute at least.

And so under those stressful conditions the excitation system tripped off with the Avon Lake.

If it's followed a couple of seconds later in this area here with the Burker units, they're all connected at 138 kV up into the Cleveland area -- and that comes off comparable in terms of it's voltage related but it's not because the excitation system fails at the Burker units, it's because similar to what Tom was describing, the lines actually trip on zone three as the low voltage condition contributes to getting into the characteristic of those protection schemes with the low voltage in the Cleveland area -- and the Burker units find themselves islanded with no load at all so they have to trip off.

The Kinder-Morgan units which are located right there in the central part, and they're significant because the very next event that's occurring is the tripping of these lines across the state, so all of these things are adding steam to an already hot condition, you might say, that resulted in those lines tripping in subsequent -- further promotion of the cascade as this is occurring.

The -- I think Gerry's trying to hurry me up here -- that tripped on a different load altogether. There's an apparent fault in the generation of the Burker transformer but there's no reported damage to that transformer so it's probably related to the undervoltage condition, the high current levels, the harmonics that might be generated under that circumstance -- there's an MCV unit that's in the Northern part of Michigan also involved with all that. And it's in a category of the plant going to the next slide --

(Slide.)

-- you'll see the red curve indicates -- next slide --

(Slide.)

-- red curve indicates the power output. It's a combined cycle plant with 12 combustion turbines and a steam turbine that is recovering the waste heat from those -- that unit, the steam turbine is what trips. It was an implant steam system trip that let the unit ramp down over time but it was jostled out of operation by the earlier Central Ohio trips as it's coming down.

So those are definite classes of interruption. Any one of these having not occurred would have slowed down -- I don't think it would have stopped this cascade -- but it would certainly have slowed it down, and it would have occurred differently than it did.

Go to the next slide.

(Slide.)

There's a couple of opportunities, windows of opportunities -- those are the two circles there at the Michigan - Ontario border and, thanks to the good, good planning and provisions by the Hydro One organization with recorders that record disturbances in a high frequency rate, we have some pretty good data from those two locations and their windows into looking into Michigan -- go to the next shot --

(Slide.)

-- and you see a time value plot. During the 16:10:40 time period and you see a very interesting look at the blue plot right here. And what you see is, this is nominal voltage coming across -- it's a little bit low. This is on the 230 kV and it's right at the interface with Detroit.

And here is a voltage suppression that is just phenomenal when you see that. You note that it occurs for almost a second.

Now this is an angular instability and at the very trough of that right there is where the Toledo - Cleveland island actually separates off into an island and it is dropped off the connection into the Eastern interconnect and, likewise, the voltage recovers. It's followed immediately by these two notches right there and if you study through that what you'd see is, that's classically a unit going out of step -- but it's not a unit.

In this case it's a collection of units, probably about 3,000 to 3,500 megawatts of units in that region that are pulling out of synch with the rest of the Eastern interconnect and that's why it's so severe -- is the 230 voltage impacted.

That's followed immediately by a little saddle that then results in two more troughs -- what are those? Do they have a different signature?

One of them is an acceleration. The first two troughs are an acceleration as the units pull out of synch and race ahead and then trip themselves.

The other two are a de-acceleration, something I would not expect to see. In fact there are several things here that we were never expecting to see. This is as frequency is dropping and, if you compare the frequencies here you find that you may have gone as high as 62 Hertz and, by this time period, it's all down to about 58 Hertz.

So there's a period right here of a few seconds for which the system is given a real ride.

If you go on to the next shot --

(Slide.)

-- and that first one was a concentration of the time value plot of data looking in from this Southern connection in Detroit. The second one here is the Northern section looking into Detroit from the Northern side of the window of opportunity there with these good recorders there from the Hydro One system.

In this case this is an impedance block and for those of you who are used to or you've seen some of the impedance characteristics of plots dealing from a static standpoint, this is a dynamic plot of that. This looks like something that one of my young engineers might have played around with a transient stability case and made something look funny by doing something weird on the system.

But this is live, real time data.

Now the color code on all of this is such that each change of color is approximately two seconds there. So you see how this goes about. And it's a really wild tornado of a roller coaster.

What is happening in this area, that is when the Cleveland and Toledo island is removed -- it's the trough of that very low voltage that you saw and things look like they might recover -- except look at the shape of this.

And you see that's the classic out of step condition as that circular swing is going out there and then there's a discontinuity right here. This is as several of the generators in the Southern Detroit area are pulling loose -- excuse me, this is the Northern Detroit area that are pulling loose.

And one of these units is actually recorded as being tripped on an out of step condition -- other tripped for a different mode of operation because they don't have out of step tripping protection on them.

And then you get into this wild circle right here. Next shot please.

(Slide.)

This is one of the first things that we saw from these recorders and this wild operation right here -- we thought there was something wrong with the data, something was wrong with that recorder -- that can't be. The system can't oscillate that fast.

And then we think, no this is some unit that pulled out of step and they're racing ahead and they're on overspeed but that would mean that it gets to 150 percent overspeed. Nothing came apart. So that's not the case.

This is an underfrequency condition. These are units in the Southern Detroit area that have been left on -- left electrically connected to the system but they are out of step and they are decaying in frequency and it's beating against the remaining system as that's happening.

Next shot please?

(Slide.)

Several weeks after this event -- six weeks to be exact, and then subsequently several weeks after that, a report came out on the Italian blackout that occurred on September 28. And this was probably -- many people didn't pay much attention to this frequency, increasing frequency oscillation that you see there, but it really stood out to me because I had just seen that in the plots that we were looking at from our exam.

It looks like this is a common theme that you need to be cautious about in terms of expecting if your protecting generators are trying to protect systems with generators on them, it looks like from one side of the world, from the New World to the Old World -- this could be a common area of a problem.

That chart was by the way borrowed from that Italian report in English.

Next shot.

(Slide.)

Some of the low frequency conditions that we're talking about, the dotted line and the dashed line right there are a perfect 60 Hertz cycle and you can see that that's not a peak to peak condition there as you're looking at the top as a voltage.

And you can see the current is following in a very erratic nature as this is still connected to the 60

Hertz system yet it's operating in this case at 38 Hertz. This is a recording that at Brownstown, which is in the Downriver Detroit area. It's on the 345 kV. It's directly connected to a pretty large coal plant and a very large thermonuclear plant -- which are the two traces of current flowing there.

Nest shot.

(Slide.)

This one now is the same location but you see the characteristic and again the dashed line and the dotted line are a perfect 60 Hertz cycle -- this is operating at 24 Hertz at this point and there are other shots that are recorded as low as 23 Hertz as this is the units -- stay energized, they stay connected.

What's happening here? Are you familiar with the sequential scheme of tripping where the generation protection engineer is concentrating on an introspective protection of his plant with the idea that the system is going to be the system that's always going to be there. I'm perfecting my plant and I wish to trip the unit off with the load very low on the unit so I'm going to use reverse power and trip the generator breakers on reverse power.

But wait, that really may not operate, so I'll put a redundant one in. That sort of -- scheme can be thought of but what happens if there is no reverse power?

And in this case there wouldn't be because it's running asynchronously. It already pulled out of step before the reverse power could ever occur and it's decaying with local loads still connected being subjected to this frequency as well.

Next shot.

(Slide.)

This is a Fourier transform. Carson talked about earlier about doing some Fourier analysis and we did some Fourier analyses of those oscillograph shots -- and what you see here is a 60 Hz signal that's obviously there at the particular round sound but the overbearing part of that is a 46 Hz -- the next trace is a 38 Hz which is about seven seconds later, and then that's followed with three shots in a row that are about two or three seconds apart in the 16:11:45 and nine time period that are in the 26, 24 and 23 Hz time frame -- and then we stopped getting traces as these units finally get removed from service -- but not by underfrequency load protection or underfrequency generation, protection -- not by volt per Hertz for whatever reason that didn't occur, not by reverse power -- but by inadvertent energization as they finally get slow enough and the voltage gets slow enough that the units trip off for those reasons.

So this was not expected by anyone trying to coordinate the protection for the units.

So there's the limit frequency condition that you weren't expecting. Next shot please.

(Slide.)

The rest of the system, while this was going on, is also -- because you can see that, while this is going on, that's this portion right here, all that dirty looking oscillation that's bleeding -- yet there is another phenomenon going on that's an excessively high frequency condition that was also going on impacting generation performance and protection in that area.

As you see the frequency escaped to 63 Hz twice in short order in the Southern Ontario region as well as the upper New York State area. And the response of a typical unit can be seen on the next shot which is a red curve -- there shows the power output from one of the large nuclear plants on the lake there in the New York area -- this one makes it -- this one almost hangs in there.

The first roller coaster ride that it gets when it gets to 63 Hz, the unit, there's a natural reduction in electrical output as it's getting accelerated and it does a ramp down like it's supposed to do to try to curb the frequency that's out right now at 63 Hz.

After that is recovered it starts to go back to normal. It was probably on its way to maybe a recovery but bang, this is a one-two punch.

Tyson is in the ring and look out, here comes the second shot. And there's another 63 Hz and it does it one more time.

You know, it may have done it -- it may still have recovered but the design engineers for this plant never really expected to have to go through this and, by now, it's out of hydraulic control fluid pressure so the unit has to trip for those reasons.

And all of these are to be expected. The unit has to protect itself and that's the reason why this comes off, drops of and, at this point in time gets a reverse power and that opens right there the generator breaker.

Now this time, this works, unlike what's happening to Detroit right here, this is how this is planned to work -- and it does work here because the frequency is still approximately 60 Hz at this point in time which is acceptable for that to operate and the unit never pulled out of synch -- but it could have been a different story.

Well, I tried to make this presentation sort of simple, tell you what I was going to tell you, tell you and now I'm telling you again what I told you. So again my conclusions here were pretty obvious. The generation outages did not initiate the cascade this time.

This all works coordinated together, transmission generation, even customer load on the demand side and it could have been any one of these elements that could have initiated this as it failed and the system is no longer adequate to get supply to a particular area and there are all kinds of conditions that relate to this but I wanted to leave you with the idea -- and this will be my last shot, Gerry, so you can blink it as you need to --

(Slide)

-- to expect the unexpected. We need to get in the mode of doing that. Earlier in the presentations that were presented and the comments made from the audience there was some discussion about involving different people in the evaluation. When the other blackouts have occurred and when this blackout had occurred there were a lot of people from planning and operations that get involved -- where are the designers in this?

The designers need to see some parts like this and be involved in this and it's a good opportunity for them, as well as -- to make any headway in this there are going to be some costs associated with that.

Tom challenged us with that in terms of go the distance, fight the fight that needs to be fought to get these things in front of the right people to make and stress the point.

I want to leave you with this thought. I am very pleased at my own personal physician does not measure my health by counting the number of heart attacks that I've had. And I think we need to get out of the mode of counting the number of blackouts that we've had or the number of times that a unit has had to be tripped by a blackout scenario, that we need to look at some of these other indicators and several references have been made to that and I think there's opportunity for a lot of different ideas to address that -- to address the health of the system.

Even down to if it's a simple matter of doing the generation testing that was referenced earlier. Phil made a comment to the fact that, in doing some of the testing you tripped off some of the units. Well, that's an indication you've actually found out something good. That wasn't something bad.

You found out that unit has a limitation and it's time to address that.

Thank you for your time. I'm sorry if I got too excited or too long winded here.

MR. CAULEY: Thank you all the panelists.

We'll open it up to questions from our investigating leaders. And we'll start with Alison Silverstein.

MS. SILVERSTEIN: I have a question for Mr. Taylor and Mr. Tatro, but the first is, verify for me that modern DFRs have GPS time synch capabilities built into them please?

MR. TAYLOR: It's whatever you specify when you buy the equipment. Are you asking about voltage regulators?

MS. SILVERSTEIN: Well, everybody who has talked today has taken shots at the need for time synchronization. And I just want -- and one of the most important and widely found pieces of equipment on the system is the breaker and most of these breakers and most of this equipment have DFRs on them and you all are telling us we need to modernize the equipment that's out on the grid so part of my question is, if we go about buying modern breakers and modern DFRs are they going to have GPS in them? Are we killing two birds with one stone by doing that?

MR. TATRO: I certainly think that what Carson said, that if you specify that that's what you want on the digital fault recorder that's what you'll get. One of the side issues that I pointed out was that you have to select what's going to trigger the digital fault recorder to activate and start recording due to storage limitations and the amount of data that's collected, you set the trigger to respond to an event and start recording.

And so that's one of the items I think that also needs to be discussed further -- are the traditional triggers that we use adequate because we certainly had line trips where digital fault recorders did not trigger.

So even if you had the synchronization there's no time stamp and no recording created.

MS. SILVERSTEIN: Thank you.

Mr. Tatro, you were talking about your definition of bulk power system facilities. As you add new facilities onto your system do you find that the facilities that meet that definition of the bulk power system facility changed?

MR. TATRO: Yes. Over time we're finding that as the system becomes tied more tightly together that more of our 115 kV facilities are starting to meet the definition and I think that I had alluded earlier that we even have some cases where a 20 or 23 kV bus meets the definition.

But there is a trend and actually it's interesting because I think the trend reflects two things. I think (1) it reflects the system being tied tighter together and (2) I also think it reflects a trend in better analysis tools and greater computing capability that allow us to simulate many more contingencies so that we're starting to find certain parts of the system that -- who knows? Maybe they've been a bulk power system for longer than we've thought.

But we routinely do studies and we keep on top on this and that's the trend that we're seeing.

MS. SILVERSTEIN: So you both have a more -- a potentially more connected system but you also have a better tool to discover that it's more connected, yes?

MR. TATRO: Yes.

MS. SILVERSTEIN: And Mr. Rousseau, would you clarify for me -- my recollection is that Rush Island was not an outage per se -- I mean, nobody actually sat around in the dark after that. It was just a sort of frequency thing that happened, is that correct?

MR. ROUSSEAU: That is correct, yes.

MS. SILVERSTEIN: Thank you.

MR. CAULEY: Any more questions by the investigative leads? Dave Hilt?

MR. HILT: Just one comment -- when I look at -- and this goes back to planning groups a little bit (inaudible) --

MR. CAULEY: Could you come up to the microphone a little bit?

MR. HILT: Yes -- it's on.

I said, as I look at some of this data and I see the things that have taken place here, I want to go back to the planning group just a little bit. I know they're not up there but certainly as I look at the number of lines that tripped here, and we talked about N - 1 and N - 2 conditions, but certainly there were many, many lines that were out of service as we went into this thing.

Secondly I look at some of the data that Gary just presented showing some of the really incredible things that happened to generation systems out there, I think it's a testament to how robust this particular system is and -- I think we need as an industry to think about maintaining that robustness in the system.

Because if we can have -- we talked a little bit about operating systems closer to the edge and so forth, if we can still have this kind of a blackout with a system that's this robust, I think we really do need to take a hard look at our planning and operating criteria and make sure that we maintain that level of reliability.

And maybe the N - 1 criteria isn't adequate and we need to very seriously consider what we really need to do to make sure that we don't have these blackouts in the future.

MR. CAULEY: Anything else Dave or Tom?

Okay and from the audience? Any questions or comments? Frank? Frank Macedo, Hydro One? I'm starting to learn the difference between IMO and Hydro One.

MR. MACEDO: That's okay, thank you.

Alison, the bus system disturbance recorder that we talked about that we installed two years ago, are time synchronized, and they proved invaluable in this in investigating the blackout and I strongly recommend that we deploy such devices much wider across interconnections.

On the frequency spectrum analysis that you've done. I'm intrigued by the notion that the frequency spectrum can give you a -- can be a precursor to problems down the road. I would have thought that you needed to go much further than that and actually model, produce a frequency domain model of -- use that data to produce a frequency domain model and determine the damping factors and monitor the damping -- when the damping gets to near zero, then you've got a problem.

So you've got a long way to go. I mean, just looking at the frequency spectrum is, to my view, not very helpful.

MR. ROUSSEAU: If I can respond to that -- yes, it's a fair comment and it's clearly the frequency analysis that is not the only bit of analysis that should be done. But we think that it's part of a complete, one portion of a complete set of analyses that should be done that would give you an indication of the health of the system.

But an analysis that has a strong correlation with -- that could be a strongly correlated precursor of system problems.

MR. CAULEY: Gary? Gary Bullock?

MR. BULLOCK: I almost hesitate to do this but Gerry, can you put up that other point that I left you in my folder?

And Chris, I apologize because I didn't have the opportunity do discuss with you earlier. My VP had given me that report as he got copy of it and the recommendations of the work that you all had done.

And we need to be about looking at ideas like this in terms of getting indicators that can give us some heads up.

What Gerry's about to put up, I got curious with respect to the approach that Dr. Wells and Chris had taken and emulated the same kind of analysis using data that was in TVA's archives so I took liberty last evening in fact to take a look at the frequency spectrum for the 14th and I came up with slightly different peaks there but they're in the vicinity of what you had accomplished and I had a different set of data that had more continuity to it than what you had available by using the scanned in data and digitized approach.

(Slide.)

Gerry, I need your assistance and go back to the chart that is on the tab back up before that.

(Slide.)

This is the 14th. But I got interested in, well, how does it compare with other days? I took four other samples and what you see here is a collection -- it's going to be busy but what you see is August 13th as well as 14th, as well as September 1st and September 13th and 14th.

And I found that there was one day, the little blue curve, happened to be very passive. But the other days were even more active than the 14th.

And I did see a pattern and I think it's significant. That's the reason why I bring it out here.

You'll note there that the period is very close to the first peak there -- is about 120 minutes. That's two hours.

The second one there is a period that comes to approximately one hour -- I mean, it's 57.8 minutes or something like that.

The third one is 30 minutes. And I'll get to a point here -- you'll see a 15 minute and a 10 minute period there and my experience after looking and being sensitized to looking at frequency excursion on the system as we were trying to do some of the earlier fact finding team work, was trying to get a calibration point, and what I was seeing, and I think other operators have seen this too, that around the top of the hour and the bottom of the hour, frequencies are taking an excursion.

And I think what you're seeing there is a fault signal of not an oscillation that's fundamental on the system, but an operator controlled or lack of operator controlled -- signal. As we're trying to meet all of these very large schedules and moving the schedules around, and our, the players in this environment now also have some inexperience in doing that and we've got a little growing and a little maturing and a little better control issues to take place.

And that's what I gathered out of that.

But I thought the initiative to go look at things like that was very important so I commend you and Dr. Wells for starting and leading me off in looking at some of this.

It probably needs more evaluation like another 50 days worth of studies on this side of things, but it's a good approach.

That's the important thing that I wanted to bring out. Thank you.

MS. SILVERSTEIN: So Gary, what you're saying is, if your interpretation is correct, this represents a better management opportunity in terms of how scheduling and unit ramping is occurring, correct?

MR. BULLOCK: Yes.

MS. SILVERSTEIN: Thank you.

MR. CAULEY: Anything else from the audience? Carson? Carson Taylor?

MR. TAYLOR: I'd like to make a couple -- two comments. Alison asked about DBR, DFR and I thought she said AVR.

DFR I think is fairly common to have, almost universal to have, some kind of time synchronization. But that brings up the question, what about power plant equipment and AVRs should also have time synchronization so you know if an overexcitation limiter operation occurs and so on. And I think that's largely missing.

The second comment I wanted to make was, maybe we should try to consider the effective reliability on when you have say a 500 kV grid, the impact of operating 115 kV lines radially instead of in parallel with the high voltage and that might be interesting to look at.

MR. CAULEY: Okay. Seeing no other hands what I'm going to do is turn it back over to our distinguished electricity system working group co-chairs for any closing comments and hopefully congratulating our panelists for fine presentations.

MR. MEYER: I think it has been a very productive discussion and so I thank the panelists on both the current panel and the previous panelists for their contributions.

Collectively there is a lot of effort that's gone in to producing discussion that we've heard and I think it's been very useful.

Thank you.

MS. SILVERSTEIN: I've learned a great deal. I thank all of you for the trouble you've gone through to think through and share with us your recommendations. I am quite excited and daunted by the challenge of taking all the good ideas that you've given us and putting them into a set of recommendations that will achieve all of our mutual goals which are that we have fewer such blackouts in the future and run a more reliable system for the people whom we serve.

So thank you very much for your contributions.

MR. RUSNOR: I want to echo the comments from David and Alison. I found them very useful and interesting and again I add my congratulations to everyone who participated including those from the audience.

This morning first thing I mentioned that we will have sessions, similar but hopefully not exactly the same as this in Toronto on January 9. I mentioned that what I would like to do with that is to make it complimentary to today's session rather than duplicate some of the areas.

So how are we going to do that? I'd like your suggestions of areas where you want to drill down deeper. I think it's probably -- maybe I won't speak for my colleagues, but to include so many of the items that have been discussed here today in the recommendations of the final report is probably not practical.

So how do we encompass the principles and the ideas that we have heard here, together with some policy issues, into a concrete and useful set of recommendations?

So if we're offering you another day to come together with us and to drill deeper in some areas and perhaps even go beyond what the topics are -- have been discussed today -- to make it more useful in developing recommendations.

Do we want to address from your perspective solutions that could be implemented in six months? In a year? In two years? Do we want to identify those and be more specific in them?

What I'm asking for is what are the actionable items coming out of this session?

We plan to have break out sessions of these five topics and potentially another topic or two depending on your sense of it and I'd like to see your comments and recommendations and I hope we have your participation on January 9 so we're still open to suggestions on what would be most useful to you because the ultimate end result of the study is going to impact on all of you and your companies and your operations.

So thank you and I really do hope that you will take some time and address your comment to either the DOE website or the NERC website which you are hopefully aware of.

Thank you.

MR. CAULEY: Okay, thank you all for being here.

And that concludes the session today, thank you.

(Whereupon the proceeding adjourned at 5:00 p.m.)