BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

- - - - - - - - - - - - - - - - - - x

IN THE MATTER OF: :

MANDATORY RELIABILITY STANDARDS FOR : Docket No.

THE BULK-POWER SYSTEM : RM06-16-000

- - - - - - - - - - - - - - - - - - x

Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, N.E.

Washington, D. C. 20426

Tuesday, September 22, 2009

The above-entitled matter came on for a public meeting, pursuant to notice, at 10:07 a.m., Joseph McClelland and Robert Snow, moderators.

P R O C E E D I N G S

(10:07 a.m.)

MR. McCLELLAND: Good morning and welcome to the Federal Energy Regulatory Commission. My name is Joe McClelland and I'm the Director of the Office of Electric Reliability.

Today we will hear a presentation from the University of Wisconsin regarding a mathematical process they have developed to identify and rank elements of the Bulk-Power System in three different interconnections.

The Energy Policy Act of 2005 was passed by Congress to ensure the reliable operation of the Bulk-Power System. The term, "Bulk-Power System," was defined as the following:

a) Facilities and control systems necessary for operating an interconnected electric energy transmission network or any portion thereof, and,

b) Electric energy from generation facilities, needed to maintain transmission system reliability.

The term does not include facilities used in the local distribution of electric energy. In Order 693, the Commission determined that, at least for an initial period, it would rely on NERC's definition of "bulk electric system" and its registration process, to determine the applicability of the reliability standards and the responsibility of the specific entities to comply with them.

Today's presentation will help educate us in reviewing this issue.

NERC's definition of "bulk electric system," is described as, quote, "general," end quote, including network transmission elements operated at 100 kV or higher. Its registry criteria includes individual generating units of 20 MVA or greater, and generating plants with an aggregate rating of 75 MVA or more, as well as black-start units or any generator, quote, "regardless of size," end quote, that is material to the reliability of the Bulk-Power System.

These criteria are important when considering the facilities that must be compliant with the reliability standards. For instance, simply shifting the voltage threshold from 100 to 200 kV in the Western Interconnection, yields almost a 65-percent reduction in the amount of transmission facilities that are covered by the reliability standards.

Today's conference will be chaired by Bob Snow, who is a Senior Engineer in the Division of Standards in our Office. Bob will introduce the process for the technical presentation today, as well as kick off the presentation by introducing the researchers from the University of Wisconsin.

Bob, the floor is yours.

MR. SNOW: Thank you, Joe. Good morning. May I also add my welcome to everyone here, to the Commission.

As Joe said, my name is Bob Snow, Senior Engineer in the Office of Electric Reliability. As Joe stated, the purpose of the meeting, is to hear a presentation by the representatives of the University of Wisconsin, concerning a Topological and Impedance Element Ranking process.

We appreciate the time and effort of our speakers, and I wish to personally welcome them.

I have a few housekeeping items, first. The restrooms are located past the elevators on the left or right-hand sides, as you leave the room. Also, at this time, please turn off any pagers or cell phones that you might have with you, or any other kind of electronic device that might make noise.

Any presentations used today, will be posted on the Commission's website, and appended to the calendar posting for today's meeting.

We'll start the presentation concerning the research funded by the Office of Electric Reliability, concerning the derivation and mathematical basis for a process that can be used to determine the ranking of elements in the grid, based on their topology within the grid and their impedance in the specific elements.

There are some 3x5 cards in the back. Please write down any questions you might have during the presentation, since we're not going to be interrupting the presentation for questions.

The cards are in the back. Please write your questions on the cards provided, and we'll pick them up, or my colleague, Ted, will pick them up right after the presentation. Please put your name and affiliation on the card. somewhere on the card involved.

After the presentation, we'll have a ten-minute break. At the beginning of that break, Ted will pick up any questions you have.

After the break, we will then have a question-and-answer period, during which Staff will have an opportunity, as well as the public, to ask questions to the University of Wisconsin, to get a clearer understanding of the process, the mathematical basis, the details of their process, and that's what we're really asking the University to do today.

If time does not allow for all of the questions to be responded to, we will put them in the record, as well as, we have an open period till October 13th, under Docket Number RM06-16.

There's a lot of very interesting things. I don't want to give, really, any more information, so, gentlemen, please introduce yourselves and start your presentation. Thank you.

MR. LESIEUTRE: Thank you. I'm Bernie Lesieutre, University of Wisconsin.

A little bit about my background: I'm an Electrical Engineer by training. All of my degrees are from the University of Illinois.

I've held positions over the last 20 years, at MIT and Lawrence Berkeley National Laboratory.

MR. SCHWARTING: Good morning. My name is Dan Schwarting. I'm a graduate student in the second year of a Master's program at the University of Wisconsin.

I earned by Bachelor's Degree from the Renssalaer Polytechnic Institute in Troy, New York, in 2008, and I've also previously worked as an intern for Central Hudson Gas and Electric in New York State, and the Independent System Operator of New England.

MR. DeMARCO: Good morning. I'm Chris DeMarco, a faculty member of the University of Wisconsin-Madison. My degrees are out of MIT and Berkeley, all in Electrical Engineering and Computer Science.

I serve as the Site Director for the Power Systems Engineering Research Center at the University of Wisconsin.

(Slides.)

MR. LESIEUTRE: All right, we'll get started with our presentation. First of all, we really appreciate the opportunity to visit with you and discuss this research. It's very interesting to us.

In the introduction, you've already covered pretty much what the background is for this. We're talking about definitions of the Bulk-Power System.

We view our task here as to develop and approach or to propose an approach to distinguish facilities that should be included in the Bulk-Power System, from those that may not be, and we're taking the approach of looking and focusing on the topology of the network, very physical, how the topology of the network impacts the operation of the network and the electrical properties of components within the network.

Our approach is to classify components, based on their potential to impact capacity resources, so that's it, in a nutshell, up front. We look at each facility and look at how it impacts the capacity resources.

To do so, we cast this as an optimization problem. We do that to uniquely relate the impact of each element on these capacity resources, and, to do so, we need to talk about how this system might be operated, and that's typically done through an optimization process.

This is a technical conference, but I realize not everybody, perhaps, in the audience, does this type of work every day, so I'd like to take the opportunity to talk about relevant background information about optimization, in general, so that will help better understand what we're doing.

Optimization, some of the terminology is, as we're trying to meet some objective in an optimal fashion, and so we'll cast a mathematical function, which we'll call an optimization function or a cost function, and then we'll try to minimize it to find an optimum.

We do this all the time in our industry, so, examples would be: Minimizing production costs or, if we're trying to make an efficient system, we could talk about minimizing energy losses.

Within the context of an objective or cost function, we declare the variables that we are going to use to minimize that objective, and we'll term those "decision variables." And, again, in the context of these examples, that would be, say, production, and we'd change production to minimize production costs or energy costs, for example.

What we're interested in, is constrained optimization, where there are additional constraints on that objective. There's two different types of common constraints that often arise:

Those that we term, mathematically, as equality constraints, and those often represent just fundamental laws of physics, for instance, conservation of energy, or, in the context of electric power or electric engineering, tier cost log, which governs the flow in electricity networks.

In addition, there are often inequality constraints that arise for practical problems. Those often represent limits on our ability to operate a network in our case.

There might be thermal limits on transmission lines, or voltage or stability limits in the system, and those come up as inequality constraints, because they only become important when you reach a certain threshold.

When we talk about those, it's possible that our modeling will introduce additional variables that aren't decision variables in our cost functions, and we'll refer to those as "dependent variables," and we'll see a little bit of that in our terminology.

The typical approach to solving these types of constrained optimization, uses a technique that uses something called Lagrange Multipliers. And it's a really clever thing.

What we'll do, is, we'll take this cost function, and, if we look at the slide, we have our original cost function, and we'll add something to it. In this case, I've only shown the equality constraints that I represented on the previous slide, F of X.

And it's clever because we had set these additional equality constraints equal to zero, so this augmented cost function, is identical in value to the original cost function. Then we add something that, when we evaluate it or solve our problem, adds absolutely nothing to the number, but it allows us to solve this problem in a very easy way.

We use just basic calculus, based on this augmented cost function, to find the optimal solution, and we just take the partial derivatives and set it to zero, if you remember your calculus a little bit.

This isn't a new technique. I mean, these Lagrange Multipliers are attributed to Lagrange, a mathematician from the latter half of the 18th Century, so this is truly a typical technique for solving these types of problems.

I wish we could claim it, but we can't. From a mathematical point of view, it's straightforward, almost mundane.

When we set it up this way, though, we add an additional variable that wasn't there before. That's called a Lagrange Multiplier, and that's necessary for when we take those partial derivatives that will actually have our constraints be satisfied.

Importantly, though, it has an interpretation in the context of this optimization. It's a sensitivity measure; it's a measure of a constraint's impact on this cost function.

So, for instance, if it comes out, we solve this problem, and it has a value of zero, then that particular constraint has no impact on this cost.

If it's not zero, it does, and then it provides a measure for what that impact is. It's the sensitivity of that constraint to the total cost.

Examples of this in the power system, are, it's very common, so, these days when we're talking about electricity markets, LMPs are Lagrange Multipliers; they're Lagrange Multipliers evaluated at locations in the network, buses in the network.

Other common ones that arise in our discussion of power systems, are flowgate shadow prices, which correspond specifically to, if we're controlling the flow along a path, a transmission path or transmission line, the Lagrange Multiplier associated with that, is called a "shadow price."

These arise very often in our field, and are commonly used, and these are the Lagrange Multipliers.

We were interested to tie this back to what we're interested in. We're interested in how a branch in our electric network, will impact capacity resources, which are located in locations in the network, at these buses, so we're interested in how a branch constraint impacts a bus constraint.

Our approach to that, is to compare the corresponding Lagrange Multipliers with respect to each of those. The Lagrange Multiplier associated with the branch constraint, and the Lagrange Multiplier associated with the bus constraint, and then that's how we're going to relate.

Again, those Lagrange Multipliers, have an interpretation as the impact of the constraint on the cost, so we're going to compare those.

And it turns out that they are not independent. The Lagrange Multiplier associated with the network and the buses, are not independent.

We want to emphasize in this here and in the next slide, that we're not interested in cost in this analysis. Of course, we operate the system at least cost and in sensible ways, but we're interested in how the network topology affects -- relates the branch constraints to these bus constraints.

We're not interested in the total cost at the end, and we're going to make those point a couple of times as we go through this. We want to spend a little bit of time on it up front.

So where we are now, is, we're assuming that the power grid is optimally operating, in an optimal fashion, or is being designed to. We do, in this report -- I'd like to take the opportunity to report where we are with the report -- we present this mostly in terms of an operating cost, and it appears as if it's an economic study.

That is intended just to present this in a familiar -- what we expect to be a familiar framework for the readers, but the actual costs do not matter with this method, and we're going to only extract out part of the optimization problems, such that the costs do not matter.

It's meant for presentation purposes, to present it this way in this presentation and in the report, which raises a very sensible question, we think: How can it not matter? If we're designing this system to be optimized to minimize some cost, how can it not matter?

I think I just said it and I'll repeat it here -- we're trying to extract part of that optimization problem that relates to networks, and then we're going to look at how the constraints with respect to branches, relate to constraints that are with respect to buses, but we don't need to look at the total cost of the system.

If you'll allow me to again say, for familiarity, we're taking the approach of casting this as the least-cost economic problem, we're going to particularly look at how branch elements affect the Lagrange Multipliers associated with the bus constraints, and look at the pattern of how it impacted across the network.

So at this point, I'd like to present the model that we're using for analyzing this network, and talk about it a little bit.

At the top, there's a cost function. A typical one would be minimizing the dollars per hour to operate a system, but, again, that isn't going to matter in this.

Then there's the equality constraints that I talked about, which represent fundamental laws of the network. In this case, we have injected power being related to angles in the network, and this combines two of the fundamental laws together: It combines TIER cost laws for electric networks and conservation of energy.

So, basically, it says that the power injection has to go somewhere. If you put energy into the network, it goes somewhere, and it's conserved.

The bottom line here, in the context of what I presented before, was an inequality constraint, where we want limits on facilities to be less than some amount.

The approach we're taking to evaluate each component of the network, is to look at them individually and constrain them, so we're going to set them to their limit, at which point we're going to require it to be limited, and it makes it an equality constraint, not an inequality constraint.

We're going to look at each one of these making an equality constraint, and, in this case, we're looking at the power flowing along a branch element in the electric power grid, so we'll step through what would be called a DC optimal power flow, with the single-facility constraint, each time we look at it, to focus on the effect of each facility individually on the network.

And so then I will return to what these As and Bs mean, in a moment, but just to say right here, they capture the effects of topology and electrical characteristics of the components in the network, and we'll emphasize that again in a minute.

So, this is what the Lagrangian function looks like when we add the additional constraints to the cost function, minimizing some sort of cost, adding the equality constraints associated with the fundamental laws, and an inequality constraint, usually, but we're going to impose it as an equality constraint, to look at each facility individually.

Then we repeat this analysis for each facility in the system.

This is just basic calculus then to solve this minimization problem of this function.

Now, to properly solve this, to find a solution, we actually have to take the partial derivatives of each of the variables in here -- the PGs, which are the generation dispatched, these Lagrange Multipliers, and the angles that we have in here, but we're not interested in solving the problem; we're interested in finding out how the network impacts the solution of the problem, so we're only going to look at one of those.

We'll take the partial derivative with respect to the angles, and we get this constraint that has to be solved, has to be honored for any optimal solution to this, and, independent of the cost functions we choose, this is a constraint that must be -- is required to be part of the optimal solution.

And it only has the information about the network in it, and so I'm highlighting on this slide, the Lagrange Multipliers. This Lagrange Multiplier, which we denote by Mu, is the one associated with the facility constraint, and you could interpret it as a Lagrange Multiplier, its effect on cost.

If we're controlling the flow along a line, it's the incremental cost of this, of changing the power flow along that line, or redispatch costs. The units will be in dollars per megawatt hour for this constraint.

The bus constraints are Lagrange Multipliers associated with the buses, are the locations, and in what is a familiar context for most of us, these correspond to the Lagrange Multipliers that are locational marginal prices in a network, and, again, the cost -- the units are exactly the same for these, dollars per megawatt hour.

MR. DeMARCO: I'll just interject. If you want to return to that slide for a moment, I think a clarifying point that might be useful to the audience, is that, ultimately, we'll require the ratio of those two quantities, and, therefore, the dollars per megawatt hour drops out.

MR. LESIEUTRE: Thank you, that's right, thanks.

And on this slide, it's the same equation, but I want to highlight something different about it.

The As and Bs represent properties of the network. The As are some matrices that contain the topological information, how the network components are connected together, and that's it.

The Bs here, correspond to the electrical characteristics of each component, and, basically, the susceptance of each component, and this is how they are combined. So this constraint has nothing in it but the topological and electrical characteristics of the network, and that's what this, the constraint, is; that's all this depends on.

Okay, and then this is a relationship between the Lagrange Multiplier associated with the line and the

Lagrange Multipliers associated with the buses.

A quick comment about their dimensions: We're looking at these individual facilities, one at a time, so this is a scaler quantity, the Mu is, whereas the Lambda is all the buses in the network, so it's a vector quantity and has lots of values.

So, where we are, is, we set up an optimization problem that we think is relevant for our task, and we've extracted only the conditions that have to do with network constraints, and the dependence of our method has nothing -- it doesn't depend directly on the cost function.

And, as Chris just alluded to, we sort of see that, beacuse the units are the same between these things, and, what we're going to do next, is look at the ratios and they will become a unitless quantity that doesn't depend on cost at all.

So, what do we do with this? How does this apply to our particular problem? We want to use it to rank the element.

And so we make the following observation, and we could go back and make that observation through the math, or we can talk about it intuitively, with how we -- what we -- how we understand the network.

But if there are no constraints in the network whatsoever, no constraints, it is the case that, mathematically, and in our intuition, that the pattern of Lagrange Multipliers associated with the buses, are equal; they have identical values.

In an electricity markets context, this would be equal LMPs across the system, if there are no constraints.

Furthermore -- and this is where we're going to use this to distinguish between elements, is that if we change things in the distribution system, this should have no impact on this fundamental characteristic of LMPs or Lagrange Multipliers associated with buses. They will remain equal at optimal dispatch.

Changing around, controlling things in the distribution system, will not cause the LMPs to change across the network. However, if we do something with the transmission system, that's not the case. It can have a tremendous impact on LMPs, if we constrain elements in the transmission network.

So we're going to rank each component, using that criteria, by the degree to which it moves the LMPs. Generators were interested in relating branches to capacity resources, and, in the context of this presentation and the Report, we're presenting that as the generators.

To the degree to which each element can move those Lagrange Multiplier -- the values of those Lagrange Multipliers, away from a uniform pattern, where the uniform pattern is where there's no constraints that affect those.

At this point, I thought it's useful to go through a small example, because the system we actually deal with, are so huge, it's hard to, without a small example, make the connections between these things, and we think it's helpful to go through a small example.

So we have this nine-bus example. The buses are the dark bars in this network. There are ten lines; those are the thin lines connecting the dark bars; and three generators, which are represented by these circles here.

And these -- I didn't write this on the slide, but the little arrows are used to represent loads, where the energy is going, so there's three of those, as well.

Okay, so taking out that equation that we had before, that's -- we were relating the bus Lagrange Multipliers to the branch Lagrange Multipliers, and we have that here, so, at each of these buses, there's a Lagrange Multiplier associated with it, which, in our familiar context, would be an LMP, and then there is this constant value that they may take, plus an effect due to each facility, if it were constrained. and so that's what's here.

To keep this in a familiar context, I'd just point out that you could consider that these bus Lagrange Multipliers, are LMPs. The constant component would be something that we would think of, if you look at websites at

ISOs, to be the energy component of the LMP, and then all the other stuff that has to do with constraining facilities, would get lumped into -- combined and lumped into a congestion component, so this is a relationship to what might be a more familiar context for it.

What we're interested in, is in this pattern, these vectors here, related to how each branch constraint might change the profile of these values here, the LMP's values, or the bus Lagrange Multipliers.

It's the pattern of how it will shift those around, if and when we constrain each component individually. In this case, we have ten branches, so, potentially, we could do ten of these and sum them together, but we're going to look at each one separately and focus on the pattern that it might impose.

In particular, we're going to focus in this case, on the generator buses. So, in the case, if we choose, down here at the bottom right of the diagram, constraining Line 7, which connects to a radial -- a radial connection to a load, and we do our calculations of the impact, the pattern of that impact on these branch and bus Lagrange Multipliers -- and I'm going to point out here, that -- and I'm going to go back to the previous slide and make this point. I should have done this here.

When we focus on these columns, we are really focusing on the deviation from a uniform value for these Lagrange Multipliers, and we've said that before, but the first here that we have multiplying Mu-zero, is that uniform value, so each one of these, is just the deviation from that.

So they sum to zero; if we add all these, they sum to zero. Anything that's uniform, is put into this vector, and so that's why this has a big positive number associated with Element 6, which would be Bus 6, and then we have small numbers, all equal, in the other area, and that's because we're only looking at the deviation of -- the impact of constraining that branch element, on the buses.

Okay, and so then we focus in at the buses that have the generators, and we see there is complete uniform effect of constraining this branch on the bus Lagrange Multipliers associated with the generators -- completely uniform.

So, in our context, that would have a very low rating. It doesn't distinguish between just normal optimization with no constraints.

On the other hand, if we were to pick Line Number 1 here, connecting Bus 1 to Bus 2, and pose that it be constrained and the power flow along it, be constrained, this does impact our dispatchable resources, in this case, the generators and the pattern that we would have for these

Lagrange Multipliers.

And I have highlighted the different areas. We've highlighted them into sort of a bluish and yellowish, to distinguish which values are positive in this vector, and which values are negative.

So, in the context of, if you will, if you will permit us again to present this in a familiar context with markets, if we have power flowing along this line and we constrain it, then it would tend to make the prices higher in one area and lower in a different area, and that demarcation line between going up and going down, is the different colors in this here.

But we see a difference at these different generator locations.

So, so far, we've introduced this idea that we can rank the elements by their potential to move these Lagrange Multipliers, away from a uniform distribution. We mathematically express this as a unitless sensitivity, so the branch and the bus Lagrange Multipliers, have the same units, so when we look at the ratio of them, that cancels out, and these answers that we get, don't depend on the cost function whatsoever, and we've shown that with the small example.

But we still have a problem. This is a small example. We actually are interested in studying interconnects, and they're large, and it is really necessary that we come up with a simple indicator, a scaler indicator, a simple number to use to rank these, instead of coming up with looking at each -- the impact on each bus in the network, for each constraint.

That's just too much information, and we need to condense it down to a simple scaler number.

What we've done here, is to choose the standard deviation of the pattern of the profile of our bus Lagrange Multipliers, and calculate the standard deviation from the unconstrained case, where they're all equal, so we'd look for the pattern of deviation.

And this is the -- over here, we have that metric, and the answers we get for this particular test system, for the radial load, which we had started with, that has zero impact in this metric, and that's a feature of this metric, that we don't want to highlight the radial load.

On the other end, the lines connecting the generators to the network, have high value, and we do want to include those and give those high values, so that's a nice result, and then it's the other lines in between. The core of this particular system that we designed, connecting the generation, gets higher, but intermediate values, and the lines that get closer to the loads, have intermediate, but slightly lower values.

At this point, I'm going to turn over the presentation to my colleague, Dan, who is going to discuss some of the examples that we've done on larger systems models.

(Slides.)

MR. SCHWARTING: Thank you, Bernie. One of these systems that we tested pretty extensively, using this method, was a model of the PJM, the Pennsylvania, New Jersey, Maryland system.

We had a model of the system that we had obtained from PJM. It was a very detailed model of their entire system.

The model included about 8,000 buses and about 9,000 transmission lines and transformers inside the PJM area. And one of the things that we were very happy about with this model, is that it had a very detailed representation of lower voltage buses, what might be called sub-transmission buses, distribution systems, and we felt that if we wanted to test this method on all of the transmission elements, including ones that would be classified as distribution, it was very important that those elements were modeled accurately in the model that we used.

This model had about 875 generators across the PJM system, but it also had a relatively detailed representation of the areas outside of PJM, and that added about 7,000 additional buses and about 8,000 additional lines to the system.

However, that representation was not as detailed as the areas that were inside PJM, so when we did this analysis, we didn't include those areas outside of the PJM area.

The analysis was performed in the program called MATLAB, the Matrix Analysis software package. It's used very widely in all different sorts of engineering disciplines, especially in the areas of linear algebra, control systems, and matrix analysis.

It has a very, very powerful and fairly fast sparse matrix package, which we used for this analysis, and we were able to perform the analysis fairly quickly, as a result.

To compute the Lagrange Multiplier sensitivities for all the 9,000, and compute the importance rankings or what we're calling the TIER values for all 9,000 lines, only took about six minutes.

One of the first graphs that I'd like to show here, is a graph basically of the distribution of the TIER values between different elements in the PJM system.

What we'd also like to show with this graph, is a little bit about how the TIER values roughly correspond to voltage levels of different transition elements.

And the horizontal axis of this graph, shows the ranking of the element, from 1, which is the most important element in the system, down to about 9,000, which is the least important, and the vertical axis shows the TIER value or the importance value on a logarithmic scale.

The zero at the top of the vertical axis, would actually indicate a TIER value of 1, the negative-1, would indicate a TIER value of 0.1, and so on. The different colors in this graph, indicate different voltage levels, and each point on the graph, is one element.

We should note that the graph -- if we hadn't tried to color-code the voltages, this graph would have just been one line. We had to separate voltage levels, shift them up and down just a tiny bit, to make the graph a little more readable, and actually make the voltage levels distinguishable.

As you can see, the top, the uppermost line, the blue dots, are for 765 and 500 kilovolt transmission elements, and those tend to be clustered right up at the top of the graph with the most important elements, which we felt was fairly reasonable that those would be rated some of the most important.

Below that, is the 345 and 230 kilovolt lines, and you can see that while they are -- they tend to be clustered at the top of the graph, there are quite a few of those down at the lower end, as well.

And as you work you way down through the lower voltages, the clusters of elements tend to shift further down the graph, and the lower voltages tend to show up as a little less important, which we felt was a fairly reasonable result.

I should also mention that the last 2,000 elements or so, at the right edge of the graph, are radial -- connections to radial loads, either step-down transformers or transmission lines that only serve radial loads, and those have a TIER value of zero, since a constraint on those lines, would have no impact on the relative values of Lagrange Multipliers or LMPs at different generator buses, and so those are at zero at the bottom of this graph.

We wanted to use this table to show a little bit about the correspondence between TIER values and voltage levels. We felt that if the system that we use to rank elements, made sense, that higher voltage levels would generally have higher TIER values, and we found this to be the case.

If you look at the center column on this table, which is the average TIER value for each voltage level, you'll see that the 765 kV TIER values tend to be quite a bit higher than 500, which are higher than 345 and so on.

However, another thing that we wanted to point out in this graph, is that the spread of each voltage level is fairly wide. For example, there are 765 kV lines that are less important than some of the 345 or 500 kV transmission elements.

And as you get down to the lower level, the lower voltage levels, the overlaps between voltage levels become fairly significant.

The next few slides here will have some sample plots of Lagrange Multiplier sensitivities for different types of transmission elements, and what these are showing, on the vertical axis, is the relative distance away from a uniform Lagrange Multiplier vector.

The horizontal axis shows that effect for each generator in the system. Again, there's about 875 generators in the PJM model that we analyzed.

This first graph here is for connection to a radial load. Because the line only serves a radial load, there will be no variation in the Lagrange Multipliers caused, if that line is constrained, so that gives a TIER value of exactly zero, and you can see, on the graph, it's basically a straight line and there's no variation in the Lagrange Multipliers.

The next graph here shows a generator step-up transformer, and, as you can see, there is almost no effect or very close to zero effect on the Lagrange Multipliers or

LMPs, at almost every generator in the system.

The exception is that at the generator which was served by the step-up transformer, which is circled in red. It's the dot that's basically at 1, and that shows that the impact, the Lagrange Multiplier impact on the generators, is a very strong impact, but just at that one generator in the system.

Finally, we have a graph here of the Lagrange Multiplier basis factor for a 500 kilovolt line. This was one of the most important lines in the PJM model, which we found after doing our analysis.

As you can see, the effect on Lagrange Multiplier Multipliers or LMPs, if this line is constrained, is very widespread. Just about every generator in the system sees an effect, if this line is constrained, and the effects vary quite a bit from one generator to the next.

After we obtained our results from the PJM system, we were able to submit those both to FERC Staff and to engineers at PJM, people who are very familiar with the system, and we wanted them to basically confirm that our results were fairly reasonable.

They did confirm that our results seemed fairly reasonable, and another useful thing, is that there were some of what we call seeming anomalies, where high-voltage lines maybe had fairly low TIER values, or, vice versa, low-voltage lines would end up having fairly high TIER values.

And PJM engineers and FERC staff were, in general, they were able to explain that, you know, because of the topology of the system or because of the way the system was built, there were actually logical reasons for some of these anomalies, and that they were consistent with the topology of the system.

So, in general, we've seen that the highest EHV-level components, the highest voltage levels, have, generally, very high TIER values, and so they would be ranked as more important.

Connections to radial loads, on the other end of the scale, have zero TIER value, which shows that they are some of the least important elements in the system, and another thing that we've seen, is that the topology of the system, more than -- to a certain extent, more than impedance, and, to a very good extent, the topology, more than the voltage level, has a major impact on the results of the TIER values, and that tends to really influence the importance of lines in the system.

We'd like to finish up our presentation now by showing you this graph. This is similar to what we showed a few slides back. This is a graph of the TIER value as a function of the element rank.

However, this graph is actually for the entire Eastern Interconnection. We were able to obtain a model of the entire interconnection, and ran our analysis on that.

One of the things that we wanted to show with this graph, was that this method of analysis, is very scaleable. This Eastern Interconnection model had about 60,000 transmission elements and about 6,000 generators inside the U.S., and so we were able to perform the analysis on that model.

It took roughly an hour of computational time, but this was done on just a fairly standard, run-of-the-mill laptop computer, so, no real high-powered computing is necessary for this.

And we also thought it was interesting that, you know, you could see from this graph, that the same -- roughly the same shape of the graph is seen here and in the PJM results, which we felt was an encouraging result; that there is a fairly high number of the elements at fairly high TIER values, and, once the TIER values start to drop beyond about ten to the negative-fifth, there, ten to the negative-six, there is a relatively small number of transmission elements that fall beyond that drop in TIER value.

And at this point, we'd like to thank you for the opportunity to present.

MR. LESIEUTRE: We'd be pleased to answer any questions you may have on the presentation, and also on the Report.

MR. SNOW: Thank you very much. I appreciate your time. That was a very clear presentation, maybe for someone who is not too worried about the math.

As I stated, we'll have a short, approximately ten-minute break. My colleague will pick up any of the questions that you might have, and we'll reconvene on the hour. Thank you.

(Recess.)

MR. SNOW: I wonder if we could reconvene.

I would first like to thank the public for their questions. We are going to take a sampling of those questions until we do them in a moment. We are going to respond to the questions concerning the University of Wisconsin's report. I would basically like to start off with that.

In kind of in any engineering problem there are many ways of solving a problem, or looking at a solution. You've identified an optimization approach. From my personal point of view I like to solve problems in a couple of different ways so that we understand, you know, if you come up with two different approaches and you come up with essentially the same answer, you have more confidence in that answer.

Kind of in that track, or going down that road, I wonder if there are any other approaches that you've thought about in how to solve this problem of how to provide a TIER Value, a TIER Ranking for each element. And if you could perhaps describe maybe that alternate approach to give the audience--to give myself, as well as the audience, a better feel for the approach, as well as why did you choose one approach versus another.

And any of the three of you can respond.

MR. DeMARCO: Maybe I'll start off.

Certainly in the course of our discussions on this we have looked at other formulations. Interestingly, one fairly familiar formulation produces different intermediate results but lands at the exact same TIER Values at the end. I can describe that a bit and say why we prefer the particular formulation we chose.

But in particular what I'm referencing is the Generation Shift Factor concept that shows up fairly often in power systems' operations.

If one were to step back and look at standard ways in which Shift Factors are used, if I may--

MR. LESIEUTRE: We actually anticipated that this might be a type of question people would be interested in, so we have a couple of slides on this.

MR. DeMARCO: Exactly. This had actually come up in previous conversations after we completed the report, but were considering other alternatives. So another way to put together what we termed the "Optimal Power Flow," a very common operational problem formulated for power systems, actually jumps immediately to establishing either facility limits or very often their flowgate limits across groups of facilities in the form of what are called Generation Shift Factors.

And if you went to the mathematics, in essence what it boils down to is you eliminate lots of the intermediate network information that we wanted to carry along to jump immediately to a final result.

In nuts and bolts it would say that if one had a package of standard computer codes used--and power system operations often compute these Shift Factors--you could actually arrive at the same TIER Values we calculated, the same number ranking assigned to each transmission facility out of Shift Factors.

The reason we chose our alternative is a little bit technical, but any time you're dealing with these very large data sets, maybe somewhat counterintuitively you're better off keeping the intermediate variables because it keeps the computation what is called "sparse." Roughly speaking, you get a lot of zeros in the math, and you can ignore any operations with that, and the computations go much faster.

So we feel the Shift Factor puts this TIER Calculation back in more familiar territory, but it would not tend to provide an efficient calculation for every single facility in the network.

I don't know if that captures the character of your question; I hope so.

If you colleagues wish to elaborate?

MR. LESIEUTRE: I would also point out that one of our purposes in conducting this was to specifically look at the topological impact and the electrical characteristics impact. And when you get to the Shift Factor, that's already--it's embedded in there, but it's not transparent; where the formulation that we put in the report is very explicit. The impact of the topology and the impact of the electrical characteristics.

MR. SNOW: One of the items you made clear in the report was that this methodology works if the model is correct. You know, you make the comment in the report that indicated that if you had all of a region modeled by eight buses, you can't really tell anything--an eight-bus equivalent, you can't really tell anything about the TIER Value of that region. And that therefore you need not equivalents but the reality.

The fact of life is there are equivalents that show up within an area. An example might be a three-winding transformer. How did you handle those type of elements?

MR. SCHWARTING: To use your first example of a three-winding transformer, those usually are modeled as an equivalent of three two-winding transformers that meet at a common, what's often called a Star Point in the center.

That Star Point is usually modeled as a separate bus which is--the bus itself doesn't actually exist, but it's modeled that way for ease of computation.

Generally what would happen is, when we did this sort of analysis we'd find that the three different windings of a three-winding transformer would each end up with their own TIER Value.

Often one of the windings may just serve a radial load. That would end up with a TIER Value of zero, and the other two windings would end up with some higher non-zero TIER Value.

Generally, and strictly speaking, the three-winding transformer is one piece of equipment. It really would not make sense to give different TIER Values to different parts of it. We feel that some simple way around that might be to just take the highest TIER Value of any of the three windings. And, you know, one of the three windings has that high of an importance, then the entire facility, the entire piece of equipment, the transformer itself, would have that high of a ranking.

We don't feel that that had any adverse impact on the accuracy of any of the elements around it. We feel that, you know, the equivalent of a three-winding transformer is, once you get outside of that transformer it's mathematically the same thing as the actual model of the transformer itself. And so we feel that that did not affect the accuracy of any of the modeling of elements around it.

MR. DeMARCO: If I may, I might elaborate a little bit on Dan's comment, because I'd almost split your question into two parts.

One is equivalencing within a facility, which would fit the description of a three-winding transformer. There I think we were very able to use the standard techniques of representing that through an equivalent and extract a useful TIER Value.

I think there is a second question of equivalencing on a more global scale, and we can take the example of the study of the PJM Network that we conducted.

There are equivalents for bordering networks--for example, all of New England was represented by something on the order of 20 buses. That's clearly a reduction in information.

I think the simple rule I put forward, you posed your question in terms of accuracy of the model. I'm going to shift that a little bit and say what's very important to us is completeness of the model.

Simply put, if I want to rank a facility, that facility better be explicitly represented in the model. If you take multiple facilities and condense them down to much smaller numbers, you can't expect to extract a reasonable importance TIER Ranking for elements that are no longer represented, that are somehow represented by surrogates.

The exact numerical values of parameters of a given facility we're not that sensitive to.

MR. SNOW: Thank you, Chris.

Just to make sure we're all on the same page, all of the information you used is classified as CEII information and, as such, I want to commend you for doing a very good job in sanitizing that to present the information but without addressing it to any specific facility. And the Commission will obviously keep that type of information under the appropriate CEII aspects.

Ted, do you want to start reading some of the questions?

MR. FRANKS: We may not get to all the questions, so we kind of went through them and took a sample set. There seemed to be some common themes in the questions.

The first question was from Paul Kiery from Reliability First Corporation: How is the original optimal LMP profile determined?

MR. DeMARCO: I think I'll step back and say we very much need sort of general qualitative properties. So I think the simple answer to that is: The LMP, or Lagrange Multiplier Profile in an unconstrained system is guaranteed by the underlying theory to be all equal.

We don't care what the value of all those equal points are; we just care that they have this pattern, this property of being all equal.

So I guess I'd say that that being the underlying optimal pattern is just a given fact that falls out theoretically from the mathematics independent of the specifics of any given network or any set of, if you did care to look at cost curves, or offer curves, those would be irrelevant.

MR. FRANKS: Okay. Thank you.

MR. SNOW: Did you want to add something?

MR. LESIEUTRE: It may be redundant but I can't help myself.

(Laughter.)

MR. LESIEUTRE: We are looking at the impact of these branch elements on the buses. And in particular in this interpretation of LMP we're looking at the impact on the profile of LMPs. So we don't actually have to know what the LMPs are. We're not calculating in the initial LMPs the specific values. We're just looking at the impact on the profiles.

MR. FRANKS: Okay. Thank you.

Another question from Paul. Please explain how the DC Power Flow modeling is used in this process?

MR. SCHWARTING: One distinction that I might make here is that we never actually run what might be called a full DC Power Flow solution. We never actually--none of our calculations actually solve for how much power is flowing at different points in the network.

And that we feel is actually a strong point of our method, that it's not dependent on things like the load level on a given day, or the generation dispatch. It's independent of everything except for the actual physical properties of the network.

That said, we do adopt a lot of the same assumptions as the DC Power Flow. For example, we use an assumption of lossless powerflow; that there is no power flow in transmission lines or transformers. And while that is an approximation, we feel it is a reasonable approximation given the sort of analysis that we're doing for this method.

MR. DeMARCO: Maybe this gives us an opportunity to point out one result that appears in the report that I think is relevant in a number of these questions.

We did as, if you will, a reality check, or a challenge to our method, where we had the full dataset for the PJM data that we looked at, including a full power flow solution at a fairly heavily loaded system condition we were left understood. In some sense that might offer a fairly worst-case test for how far off what's often termed the DC-approximation might be.

So within the report there's a plot that's labeled as Figure 3.3 that basically steps back and said, well, if we pretended that we had the exact system operating point the full load flow data as we did in this one PJM case, suppose we went back and recalculated all our TIER Values based on that, as opposed to the DC-approximation that we're promoting which doesn't need information of that level of detail?

And we plot these two. One set of values on a horizontal axis, one set of values in the, if you will, hypothetically more exact case on the vertical axis. If our approximation is good, we should get a 45-degree line. The value using DC produces the same value as the one with the Full Solution.

And if I refer you to Figure 3.3 in our report, we display a plot that, to visual inspection, to the accuracy you can get on an 8.5 x 11 page, is pretty darn close to a perfect 45-degree line. We were quite pleased with that result.

MR. FRANKS: The next question comes from Kevin Goolsbey from SPP. This methodology seems to say that all generation is critical to the BES. Is this the assumption that you used for the analysis?

MR. LESIEUTRE: We do favor generation in particular in our analysis, and that is motivated by our understanding of the statute which explicitly indicates that generators are important, and this explicitly excludes local distribution. So to some extent that is correct.

MR. McCLELLAND: Let me jump in there for a second. Can you get your slides back up, Bernie? Go to that one slide--I thought the same thing from the example that you showed. It seemed to say that every one of the generators was a major impact.

But there was a slide where you lost the GSU. And that showed no impact on the system at all. Now is that relevant to the question? Because it looked to me as if you lost a generator and there was no impact on LMP, and in my own mind I attributed that to the fact that it was lost within the PJM area.

Do you recall the slide? It was part of your presentation, Dan.

MR. SCHWARTING: I think what we're trying to show with this slide is really more that the--

MR. McCLELLAND: Can we get that slide up? Yes, that's the slide. What slide number is that? 30. There you go.

(Slide shown.)

MR. SCHWARTING: I think what we were really trying to show here was that if there was constraint on the generator step-up transformer, or similarly a line that independently connected the generator to the rest of the network, that constraint would affect--it would have a fairly large effect on the Lagrange Multiplier at that generator. And it actually does have a very small effect. It's not exactly zero, but on this graph it is very close, a very small effect on the Lagrange Multipliers, or LMPs at every other generator in the system.

And depending on the size of the system--well, first of all let me say that one result of this is that any generator step-up transformer actually ends up having the same TIER Value. They will all have a plot that looks almost identical to this one, the only difference being that the single generator that has the very high impact will change which generator that is from one GSU to the next.

As a result, they all do end up having the same TIER Value. In very small systems such as the 9-bus example that we had earlier in our presentation, that equal TIER Value for all GSUs will usually be the most important, the highest TIER Value in the system.

As the system gets larger, that value usually will start to drop and not be the most important. If I may jump back actually a couple of slides here, let me actually go to the one for the Eastern Interconnection, the last slide in our presentation here.

You can see just above the TIER Value of .01 there's a flat spot in our graph. And that flat spot in the graph actually indicates that that set of generator step-up transformers, or radial generator connections, that all have the same exact TIER Value. And as you can see in this graph, they're not the most important--they're no longer the most important elements in the system. They are still fairly important, but there are some transmission elements that rise above that in importance once you get to a larger system.

MR. McCLELLAND: Okay. I think that illustrates the work in process. I didn't mean to preempt the question, but I think the question was related in importance. And in looking at the graph, if you can get that back up, looking at the graph that does place the generators and the generator step-up units, although the individual loss of a GSU, which is equivalent to the loss of the generator, shows up as sort of a single-point anomaly in that particular slide. And who asked that question, Ted? To Kevin's question, it does speak to Kevin's implication. It does look like the model weights individual generators or GSUs at the top part of that curve, the flat part of the curve, that you indicated on the cursor. So I think that's a good question to help me put this slide into context.

MR. FRANKS: Okay, this is a question from Alan Moser, APPA. At page 46 you describe an anomalous reading of a generator connected to the network by two 69 kV lines. If that generator had been connected by a single 115 kV line, could the TIER Value equal the sum of the 69 kV TIER Value?

MR. SCHWARTING: In that case, the TIER Value of a single connection to the rest of the network would not have been--I don't believe it would have been exactly the sum, but it would have been roughly equal to double the TIER Value of either one of those two 69 kilovolt connections.

Another thing that I might mention here is that if there were just a single connection there that would be equal to any GSU's TIER Value or, as we just mentioned, any other radial connection to a generator. And that value actually wouldn't depend on the impedance of the line or the voltage level. If that were a 115 kV line, or anything from very low voltage up to a 345 or even higher kilovolt line, the fact that it's a radial connection to a generator actually sets its TIER Value independently of the impedance or any other properties of that line.

MR. FRANKS: Another question from Alan. Are all of the 69 kV elements in the PJM Region included in the model that you guys were given by PJM?

MR. LESIEUTRE: I don't know the answer to that. What I would say about the models that we've examined is we didn't--I don't know that there are any special requests beyond what standard models they use.

MR. SNOW: To maybe add to that a bit, the PJM

Model was obtained via the usual approaches. It's a snapshot from their Energy Management System. So it is the model that they use to operate the system. It may or may not include every element. Our comment before was that we're looking at a model and we're looking at the elements in the model that provide a ranking.

Anyone who's ever played with models or has had modeling information understands that they are always a work in progress, and one needs to check and validate that all of the important elements are there. This is the best model we had at the time.

MR. DeMARCO: Just as a slight elaboration. It doesn't completely answer the question, but I might refer back to slide 36 that showed the count of facilities or buses actually in this case at each voltage level as they were used in that model, and in particular there were 930 69kV elements, over 2000 elements below 69 kV.

MR. FRANKS: Thank you. The next question is from Michelle Mizamori from WECC. There are many reliability issues beyond the thermal limits, especially in a stability-limited system like WECC. How does the model consider cases where the system may not survive the transient phase after a disturbance?

MR. DeMARCO: I think at this stage we would say that we match fairly common industry practice of representing stability and voltage limits as proxy limits. A full transient stability analysis, event by event, is beyond the scope of the model that we've presented here, but we do feel that we're in keeping with the vast majority of current industry practice through proxy limits.

MR. McCLELLAND: I beat him to the microphone--

(Laughter.)

MR. McCLELLAND: I want to ask a question, or at least offer an observation. This model as sort of a basis. So it identifies, and then it ranks every element within the interconnections that you look at. So you're looking at all the transmission lines, all the buses, and all the generators, everything, thousands of them.

That identification and then ranking is one--it's sort of one basis. That's one data set. That could be compared, can it not, to elements that might be ranked and rated in say a stability study, or stability analysis? And those two could, I imagine they can be compared because there's nothing within your study that wouldn't allow that, and then we could see if there is a--I mean, this could be under the further category that they could be put together to see what might fall out, where there might be gaps or overlaps or even confirmation between the two.

I don't know if that's the point you wanted to make, Bob, probably not, but I got to the microphone first.

MR. SNOW: I think the point I wanted to clarify was a little more in the weeds, or in the technical aspect. Certainly entities will do dynamic stability runs and come up with results. Those results are used in operations today over the entire, all three interconnections.

WECC has certainly dynamic simulation issues, but there are also ones in ERCOT as well as in the Eastern Interconnection. PJM, at one of their last planning committee meetings, made a presentation on some of their specific areas.

Those, as you've identified, have, at least up until today, have been used as proxies. You know, I know I can operate the system reliably from a stability point of view if I stay within X limit, or Y voltage, or some other characteristic, some proxies involved.

If I understand you correctly, you have included whatever those proxies might be, whatever that limit might be. In your analysis you constrain the facility, not necessarily to any specific value, but the facility is constrained, and come up with a value.

So if the value happened to be X or Y or ZZZ, the methodology doesn't care? Did I understand your method correctly?

MR. DeMARCO: In that sense, yes. And here I would emphasize probably the value that this method does, shall we say, hypothesize a constraint on every single possible facility. So any proxy constraint limits that you came up with, the sort of, you know, they come up with geometric shapes in the space of limits, any of those could be captured because we look at a potential limit on every single facility.

MR. FRANKS: Okay, a question from Alan Moser, APPA. Can you please explain the rationale for stating the TIER Values in terms of Standard Deviations?

MR. DeMARCO: Forgive me if I'm speaking too much. I'll step back to the underlying objective in a conceptual sense, just to repeat the observations you saw in Bernie's presentation.

The premise here is a network that experiences no constraints, see a perfectly flat, all-equal profile of Lagrange Multipliers. The key observation maybe that motivates the limiting cases is, if we put a constraint on something that was purely in the distribution system, you would still see that perfectly flat profile of Lagrange Multipliers.

And we certainly recognize that if you constraint something that's a very important major transmission facility, it pushes those Lagrange Multipliers all over the place. So, roughly speaking, we wanted a single numeric value to measure the distance away from an all-flat profile.

Standard Deviation is a familiar formulation of that, and if you think a little bit--I hope I'm not pressing statistics too much here--you subtract out the average, which in our case says subtract out the best fit of an all-flat profile, and then measure how far away from that you are.

There are other measures available in mathematics. If I were to get a little technical, the generalization of the idea of a distance in mathematics is what's called a "norm." The Standard Deviation corresponds to what's called the Euclidian Norm, which happens to be exactly distance if you do it in two dimensions or three dimensions.

So I would argue that we pick sort of the most common and, in some ways, most intuitive measure of distance away from that all uniform profile.

If you perturb to some of the other choices of distance up to some sort of degree of changing that measure, you'd keep the same ranking. If you go to some very extreme changes, you could begin to change the ranking. But I would claim you would wind up with distance measures that simply aren't very sensible.

MR. LESIEUTRE: I would like to add to that that this is something we gave considerable thought to when we weren't putting this together, but it doesn't really appear in the report of the options. So when we get to a final report, we would like to expand on that discussion.

MR. SNOW: But the key result, just to summarize, is that any typical measure of a norm will come up with maybe some differing in values. The numeric number might change, but the relative ranking would be preserved.

MR. DeMARCO: Correct.

MR. FRANKS: Okay, for the next question could you bring up on the slides your 10-bus model that you had up earlier?

(Slide.)

MR. FRANKS: Okay, so the question is: If buses B-5 and B-6 were connected by two lines, let's say L-7 and L-8, would the TIER Values for L-7 and L-8 be non-zero?

MR. SCHWARTING: IN that case, the TIER Values for those two lines still would be zero. The reason is that, if either one is constrained the differences in Lagrange Multipliers or LMPs at the three generators still would not be affected at all.

What I might add, though, is that if bus-6 was connected to a bus, to bus-5 and to another bus, say if that new line went from bus-6 to bus-4 instead of another line from 6 to 5, then there might be a slight impact since bus-6 would be part of the network and it would be possible for power from one of the generators--there would be a possible power flow path from one of the generators to another that would flow through bus-6.

If the new line was simply in parallel with line 7 and only connected to 6 and 5, there would be no possible power flow path from one generator to another that went through bus-6. So it would be physically impossible for the power to flow from 5 to 6 and back to 5.

MR. SNOW: I thank you very much for your presentation today. We have finished with the questions. Are there any closing remarks you would like to make?

MR. LESIEUTRE: Again, we appreciate the opportunity to present this work and we look forward to more questions and preparing a final report.

MR. SNOW: Thank you. As I stated before, the Docket RMO-16 will be open for 30 days from when the report was put on the web site, which was the 11th of September. With weekends and holidays in there, that comes out to about October 13th. This is a preliminary report. We will use the questions and comments and certainly the questions here to come up with some additional information.

Thank you, very much.

(Whereupon, at 11:38 a.m., Tuesday, September 22, 2009, the technical conference in the above-entitled matter was adjourned.)