GDO Virtual IRTOC Workshop – Day 1

YAMIT LAVI: None of the information presented here is legally binding. The context included in this presentation is intended for informational purposes only, related to the inter-regional transmission operational coordination project. The purpose of today's meeting is to ask you your input regarding IRTOC topics.

To that end, it would be most helpful to us if, based on your personal experience, you provide us with your individual advice, information, or facts regarding this topic. The objective of this session is not to obtain any group position or consensus. Rather, NREL and GDO are seeking as much input as possible from all individuals in this meeting.

To most effectively use our limited time, please refrain from passing judgment on another participant's recommendations or advice and instead concentrate on your individual experiences. And this Zoom call is being recorded and may be posted on DOE's website or used internally. If you do not wish to have your voice recorded, please do not speak during the call or disconnect now.

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So if you have any technical issues or questions, you can type them in the chat box and select Send to Tim Meehan, or you can send him an email at timothy.meehan@nrel.gov. And I think he can put his email in the chat box now to everybody if you need to send him an email.

And today, we'll be using the Q&A function within Zoom. So we encourage you to ask questions during the workshop. And you may ask them through the question and answer box, and we'll address those questions at the end of each session. And you can also unmute and ask questions during our question and answer sessions at the end of each session. And the Q&A and discussion portions of this meeting will not be included in the recording.

So first, I'll go over the agenda for day one of this workshop. We have a welcome and kickoff from Jeff Dennis, who I'll introduce shortly. We will then have a panel of experts to discuss the North American experience on inter-regional coordination. And we'll then invite our colleagues from Europe to share their experience on the multi-region market coupling.

And finally, last on today's agenda, we'll have the project lead at NREL, Yonghong Chen, to give some background on inter-regional coordination project. And we plan to end day one of this workshop around 1:00 PM US Eastern time.

So to kick off today's meeting with Jeff Dennis, the deputy director of the transmission division at the Grid Deployment Office. We'll start off with some opening remarks, so I'll hand it over to you now. Welcome, Jeff.

JEFFERY DENNIS: Thank you, Yamit. Good morning, everyone. Thank you so much for being here for this important workshop today. Sorry, you can tell my dog's excited if you could hear him in the background, as well. He's excited about this topic.

But thank you so much, in all seriousness, for the time that you're going to spend with us over the next two days on this critical topic. Let me introduce a little bit about GDO, which will give you a little bit of an understanding of why we think supporting this work is so important.

So the Grid Deployment Office is part of the undersecretary for infrastructure here at DOE. And as our name suggests, we are focused on deployment of critical infrastructure needed for reliability, resilience, and clean energy transition. And so we focus on what I'll call three lines of work here.

One is ensuring resource adequacy by supporting critical generation resources, and expanding and enhancing wholesale electricity markets, and engagement in those markets. We're also catalyzing the development of new and upgraded high-capacity electric transmission lines and improving distribution systems nationwide, all with a goal of preventing outages, enhancing resilience, and ensuring a reliable and affordable clean energy transition.

So we can jump to the next slide. So much of the work that we're talking about today is inspired by the National Transmission Planning study, and much of the learning that we've achieved in supporting that work and working closely with partners at and NREL, the National Renewable Energy Laboratory, as well as Pacific Northwest National Laboratory.

This unique, first-of-its-kind, really, study is a comprehensive multi-scenario analysis of, what are our long-term transmission needs going to be, looking out to 2050 under a variety of different scenarios, different, looks at what we think the future will look like? As well as potential solutions to those needs. And we set out on this work over two years ago now. Even before GDO was an organization within DOE, our predecessors in the office of electricity really envisioned this project with a number of objectives. One is to identify inter-regional and national strategies that will be necessary to accelerate cost-effective decarbonization while maintaining system reliability. Second, inform regional, and especially inter-regional transmission planning processes by engaging stakeholders in dialogue and identifying viable and efficient transmission options that provide broad-scale benefits to electric consumers under multiple scenarios of the future.

So again, sort of emphasizing that multi-scenario look at what our future transmission systems need to look like, particularly as we see decarbonization continuing to occur in response to state policies, consumer objectives, and, really, just cost declines in these technologies.

We're looking forward-- we're really in the final stages of wrapping up this report and looking forward to sharing final results in a report and in webinars and other delivery vehicles later this year. So really looking forward to bringing those results to the public. Next slide.

So why are we focused on inter-regional transmission, operation coordination in this work? And really, what are we talking about when we talk about inter-regional operational coordination? So the NTP study that I just talked about, and even those of you who are familiar with our national transmission needs study, our assessment, analysis of future transmission needs, looking out on a bit of a shorter time frame. But they both show a clear need to expand our transmission systems inter-regionally to make sure that we can support large transfers of power across regions from where it's available and where it's cost-effective to where it's needed. So these studies all show this critical need for inter-regional expansion, but they assume that we will have improved and enhanced planning and operational coordination among entities, whether those be neighboring systems, if you think about the RTOs and the ISOs or neighboring large utilities in non-RTO and ISO regions.

These studies show that inter-regional expansions are the most reliable and the most cost effective, but they assume that we will do more than we're doing now to really plan inter-regionally and to operate efficiently on an inter-regional basis. And so this study is really-- or this work is really intended to look at, how do we answer these questions about inter-regional operational coordination?

Today, many neighboring market systems have agreements, like joint operating agreements, that set forth a process for how to manage flow across regional transmission organization or regional planning entity boundaries today. But what we find is that there are market and operating barriers and inefficiencies today that can pose both reliability challenges, as well as market risk.

We're leaving options on the table today to more efficiently operate across regions and bring lower consumer costs, more new clean energy, low-cost clean energy resources to customers. I would commend to you in particular, and many of you saw it for pre-reading, important work that NREL released last week, looking at some of these existing market and operational barriers that are preventing us from capturing the value of inter-regional capacity today and will certainly prevent us from efficiently expanding our inter-regional connections to meet future needs in line with what we're seeing in all of these different studies. Next slide.

So our goal for this work is really-- I think I've kind of already covered this, right? One, we want to answer these emerging questions that we hear about, how does a grid that's connected more inter-regionally, that has many more links across regions, across interconnections, how can that type of system be operated reliably and efficiently?

How do we accommodate these larger transfers of power from where it's available to where it's needed, particularly in extreme weather events and things like that? How do we do that reliably and efficiently? What operational practices and components do we need to have in place?

And we also would like to improve existing market to market congestion management processes. How do the markets price inter-regional flows? And how do they optimize for long-distance HVDC transmission lines, both now and in the future? Because much of what we see in our study work is that much of the most effective future inter-regional transmission capability will be HVDC transmission line.

So how do we optimize those and integrate them into the markets in a cost effective and reliable way? So those are the questions that we are looking to answer. And so as Yamit really highlighted there at the beginning, this workshop is about learning from experts in industry, sharing best practices, learning from you all about how we are accommodating these kinds of transfers today or not, and what do we need to do to be able to do so in the future?

And we also want to solicit feedback from stakeholders, from industry, on method and approach to studying inter-regional operational coordination and assessing options for the future. So with that, I can't remember, Yamit, do I have another slide, or is that it for me and my introduction?

YAMIT LAVI: That's it. Thanks, Jeff.

JEFFERY DENNIS: That is it. Yeah. So again, thank you so much. This work is really important to me personally, as someone who's been around this work for 20 years, spent lots of time at FERC, thinking about, not just, how do we bolster regional planning, but also, how do we continue to encourage inter-regional planning and cost-effective expansion?

It's very important work for our office and just couldn't be more thrilled to be able to support this, support the work of NREL and the other labs, and to work closely with all of you. So thanks, again, for the opportunity to set the stage a little bit, and looking forward to being with you as much as I can over the next couple of days.

YAMIT LAVI: Thank you, Jeff. I can just go ahead and introduce the next set. So we'll have, first, our North American experience sharing session, which they'll share their experience and challenges with regional coordination. First up, we'll have Timothy Aliff, I hope I said that right, from MISO.

TIMOTHY ALIFF: Yeah, good morning. So my name is Timothy Aliff, but no worries. I've had a long experience of my name being mispronounced, as I'm sure a lot of us have. So no worries. Let me pull up my presentation. And then if I can get a verification that you can see what I'm presenting.
YAMIT LAVI: Looks great.
TIMOTHY ALIFF: Looks good? OK. So I'm going to talk today about MISO's experience with seams optimization and management. So a little bit about MISO, and I got a little bit more details on my next slide. But we're MISO. We sit in the middle of the country, hence the name, the Midcontinent Independent System Operator.
We're over 15 states, US states, and then also the Canadian province of Manitoba. And we work with our seams partners to manage congestion. I previously mentioned about the joint operating agreements. We have a lot of those in place that helps coordinate with our seams partners.
And then to implement those agreements, we got a lot of complex tools, processes, and even higher-level coordination and collaboration that we have. One thing about where we are is that each of these agreements are unique agreements that we have with our seam partners.
And each of us have varying priorities, objectives, and ideas about fairness and what causes challenges so that as we talk about the expansion of the transmission grid, I think the engineering piece and the market design piece is probably the easy part when you come into the-- you have companies running businesses and the bottom line and stakeholders and shareholders at play. That puts a little bit more complexity into what needs to occur as the transmission system and the US electric grid transitions to more renewable and less carbon resources.
And so the point of my presentation today is that trying to standardize on something, there's-- I'll present something here at the end that's already out there as a standardization. But as you try to overlay different thoughts and opinions on top of a transmission system and unique experiences or tools or agreements, depending on which seam you're talking about, that kind of brings in a level of complexity and then reduces the efficiencies.
It was previously mentioned about, how do we do this reliably and efficiently? Having these different agreements and different things in place can reduce some of those efficiencies.
So here's geographically where MISO is, the MISO region. We have three regions. That's what you see here on the left. We operate four control centers. We have two here in Indiana, our headquarters in Carmel, Indiana. We have a office in Little Rock, Arkansas, for our South region, and then up in our North region, Eagan, Minnesota.
As I mentioned, we have 15 states in the province of Manitoba. Our peak demand, 127.1 gigawatts, set back in 2011. Our wind peak is 25.6 gigawatts. And you can see these numbers are recent. This solar peak, I left it the way it is here because in February, our peak was 4.5 gigawatts, but we just surpassed that with over 6 gigawatts here just a couple of weeks ago.
So in just four months, our solar capacity or solar energy has significantly increased. So we're seeing quite a bit of influx of solar generation into our footprint, and hence a lot of the reason why these changes need to occur.
You can see at the bottom slide there, with our increase in our wind and solar and the reduction of our carbon, if you will, fleet, we've had about a 32% reduction in the carbon in our footprint since 2014. So we've definitely seen quite a bit of change, going from a very coal-heavy fleet to less coal. But we still

have about 30% coal, about 30% natural gas, and about 25% to 30% in that renewable range, and the balance is nuclear and other generation.

So I like this slide. I purposely picked this slide with this picture because it shows the complexity. It shows that there's a lot going on with our-- you see MISO in the green in the middle. And this is a very busy graphic of all of our neighbors, all of our seams partners. And I purposely chose it, the busyness, because it is a lot.

And each one of these entities has their own agreement. We try to come off-- start with agreements, but as you move to a new area and try to develop a new agreement with a new area, the priorities and the unique values, if you will, of those entities come out in those agreements. And so then the agreements end up being more unique.

But from a reliability and an operations perspective, we are part of the largest machine in the world here in the Eastern interconnection. So what happens in one part of the Eastern interconnection impacts all of us. We know that. And so that, it just highlights the importance of, why do we have to coordinate, and why do we have to ensure we have processes in place to manage the grid reliably?

Talking about extreme scenarios here in the second bullet, we've had situations where a neighboring entity got into a rolling blackout situation and because MISO was-- MISO was able to adjust some of our procedures, if you will. We have a process that requires curtailing some transactions, and we allowed some of those transactions to occur so that our neighbor didn't have to curtail as much through rolling blackouts.

We've also seen where transfers across our system supported neighbors. And we took actions internally to allow more of those transfers to occur and just continues to highlight the ability and the need for us to coordinate across regions. And another complexity is that we have markets and non-markets as part of this, so MISO, SPP, and PJM, some of the bigger markets. And then some of the other areas around MISO are non-markets and operate more in the old method of point-to-point sales and dispatching and managing their own electric grid.

Some of the processes that come out because we've developed agreements with our different neighbors. So this slide is just kind of, as you develop these agreements, you have to come up with processes to implement those agreements or to ensure those agreements are followed.

Our flow gate management process. Flow gates are the pathways, if you will, that may get congested across seams areas or even internally. But we create flow gates to help manage these and flows through the processes and tools that we can operate and manage the congestion across our seams.

In our congestion management process, we have what we call market to market process. So it allows between MISO and SPP and then MISO and PJM to dispatch our markets as if we were one market related to congestion and congestion management. As part of that, we have to calculate, what is our market impact, our market flows on the flow gate, on the transmission system?

And the idea behind that is that we have to allocate-- it's one thing to provide relief on a flow gate. It's another to say that you need to pay for that relief. And how do you determine what is your rights to the transmission system? And that's what this allocation aspect of it is.

As the MISO transmission owners have built the transmission system, they've gained rights, if you will, to that transmission system, the ability to flow power on the transmission system. So how do you allocate those rights, and who owns those rights? And as we work with seams and we plan the transmission system and MISO builds transmission, that does increase the rights around our system and the right to flow power across the system.

We use the interchange distribution calculator, which is a standard process, a tool that all of the Eastern interconnection uses to manage congestion. It's a way to input what we're seeing for congestion and provide out what response is needed related to those congestion and who needs to move and provide the relief related to that congestion.

And then, how do you use the transmission system? How do you sell transmission service in a deregulated wholesale transmission environment? You have to make the transmission system available to those that want to access it. And so we have to calculate, what's the capability of the transmission system? And so we develop these processes in order to do that.

And you can see the different names here. But we have NERC standards that provide the minimum standards. And then above that, we have different priorities and different logic that applies, depending on whether we're talking with markets to non-markets or specific entities across the interconnection.

So I kind of mentioned, but each company, each one of our seams members, our partner is a company that has different priorities, objectives, and ideas of what's fair. They look at, they're out there for their customers and their stakeholders. That's not wrong. That's just the nature of the way things work.

And so, how do we work through those, where our customers, our stakeholders want different things and want different outcomes? Each of us have a varied pace of resource fleet change. Some parts of the Eastern interconnection are seeing a larger growth in renewable just because of the ability. They're in wind-rich areas or solar-rich areas, if you will, from a fuel aspect.

And so you see those areas advancing further from a resource fleet change. And what does that mean? If one area is has more renewables and is advancing faster in that change compared to another area, and what does that mean from a-- what do they value, and what do they prioritize?

And then each MISO's across 15 US states, and each one of those states has different regulatory requirements and restrictions. Some states have regulated or pushed a heavy renewable agenda and other states have not. And, how does that play into the regulations and specific agreements that we may have to come into play with when we interact with our neighbors?

And the point of our conversation, as the grid changes, we can't operate the grid in the ways that we've always operated the grid. The generation resources are in different places, which has led to congestion and uncertainty in different areas that we can study and try to predict where they are.

But there is an aspect of uncertainty of, what time will the wind blow in Minnesota versus Iowa, and what does that do and change to the transmission system? So it requires a higher level of coordination and possibly new processes in order to manage through this increased congestion that may come because of that, because we find that the pace of the renewable resources moves more quickly than the new transmission system can come in to account for it.

Just an example of that, MISO's MVP, we built quite a bit of transmission about 15 or so years ago, at least put it on the books, and it was fully prescribed before the transmission came into service. And so that we had the renewable resources, the generation that it was being built to provide and enable was already online before the transmission system could come in to account for that.

And so finally, the operators-- at the end of the day, the operators have to manage through this congestion. And so developing the tools and processes for them to do that and to do it reliably and efficiently is very important.

And my final slide. So my point here is that we should try to standardize, whatever that standard might be. An example of standardization that's out there is related to the NAESB standard, WEQ-008, related to transmission loading relief. So it's colloquially called parallel flow visualization.

And so it was a change a couple of years ago that helped kind of put everybody on the same footing, as far as, how do they calculate the flows on your system and the flows on your neighbor's system, and what is your impact on that? So it was codified in the NAESB standard related to transmission loading relief. And transmission loading relief is, we have congestion, I have congestion on my system, but I know that my flows are not the only flows on it. So my neighbor's flows are on my system, how do I determine how much my neighbor should provide relief or how much should I provide relief and try to do that more equally or in a more equitable manner?

And it does a fairly good job across markets and non-markets because the calculations are the same across each area. On top of this process, the one-off agreement aspect of this is that each of the markets calculate overrides to these-- to its base calculation, which then, because of historical agreements, the joint operating agreements that was mentioned previously.

So the final message here is that standardization leads to improved equity across the regions and provides even more efficient ways to reliably serve the load. So that is all of my slides. I believe we're holding questions, but that's all I have to share today.

YAMIT LAVI: Thanks, Tim. Great presentation. Do you want to go ahead and introduce the next speaker, Yonghong?

YONGHONG CHEN: Yeah, sure. Can you hear me? Yes, good. Thank you. Our next speaker is Dr. Feng Zhao, the manager of market solutions and operations technology at ISO New England. Dr. Zhao will discuss inter-regional interchange scheduling coordination.

FENG ZHAO: Can anyone see my shared screen?

YAMIT LAVI: Yes, looks good.

FENG ZHAO: Thanks for your confirmation. Yeah, so today, I'm going to share the experience that ISO New England had with New York ISO on inter-regional interchange scheduling coordination. So I will introduce the currently implemented coordination scheme, so-called CTS, and also a few other design options.

So here is a quick outline for my talk. So I will give a kind of a introduction of the background about this coordination. And then I will summarize the currently implemented so-called coordinated transaction scheduling design. And then I will talk a little bit about the performance of that design, which has been implemented for almost 10 years.

And then I will talk about two other alternative coordination designs that were discussed along the CTS design. And then I will conclude my presentation.

So first, a little bit background. So the goal is really to improve the efficiency of inter-regional electricity trades between New England and New York. So which makes a little bit easier for us is that for New England, we only have this one major neighbor, which is New York ISO. So that makes it a little easier than what MISO has, with multiple neighbors with different kind of objectives and goals.

So then in 2011, our stakeholders discussed, really, two options of improving the efficiency of inter-regional electricity trade. One is the so-called tie optimization and the other is the CTS. So I will introduce a little more on these two options, and you will see them, these two options, are quite, actually, similar.

And then CTS was launched by the two ISOs on December 15th, 2015. And then after its launch, our external market monitoring unit evaluated the CTS performance after the first and second years of implementation.

So here is a highlight of the CTS design. So we first identify several main causes for the inefficient interchange scheduling. So the number one is, really, the latency. Prior to CTS implementation, the two ISOs had this hourly interchange scheduling. So which means before the starting of the hour, the ISOs will determine the interchange flow and then during the hour. So the two ISOs will just fix that interchange in their own economic dispatch processes.

So there is a latency, which means when we fix the interchange prior to the beginning of the hour, so the system condition at that time could be quite different from the system conditions during the hour. So that introduces the latency inefficiency.

And then we also have this non-economic clearing cause of the inefficiency because prior to the CTS, we really have-- the two ISOs have very little coordination on their economic clearing. So we run our own economic dispatch with the fixed interchange that was determined prior to the hour.

And that fixed interchange is based on this-- each market has its external transaction bits, so participants participate both New England New York market, but on separate bits. And if they both clear, and then we'll just schedule that cleared amount. So there is really little coordination in terms of economic clearing.

And the last one is the transaction cost. So we did have fees and charges levied by each ISO on external transaction services. So those are-- we see them as a disincentive to engaging more efficient trading. So you can get more details about this inefficiency causes in the link below.

And then what's implemented as a so-called CTS coordination scheme has several features. You can see how we address those inefficiencies through this CTS. So one is that we use more frequent scheduling, which now is we do every 15 minutes scheduling.

So as compared to previously was hourly scheduling. And then also, we introduced this new external transaction format of interface bit. So essentially, interface bit is just-- you can think of a price spread bit. So participants will specify the price differences they are willing-- under which they are willing to do the transaction, which is different from previously, they have to submit separate bids, which they have to estimate the LMPs in both markets.

And then the third one is, really, the coordinated economic clearing, which I will give an example in the next few slides, see how the coordination is done. And then the last is elimination of fees and charges for those introduced interface bids or CTS bids. Those bids are-- as I mentioned, they are basically spread bids, price spread. So they are purely financial bids, so we eliminate the fees and charges for them.

And then CTS, this scheme, is implemented on New York North interface. So we do have three interfaces with New York. So New York North is the major one, which is composed of, I think, seven AC tie lines. And then we have another AC single tie, which has a controllable flow. And also another one is cross-end cable, which is a DC line. So the implementation of CTS is on the main, the major interface, which is New York North, including seven AC ties.

And then under this CTS designs, really, the two ISOs actually have different roles. So new England ISO is so-called receiving ISO, so receiving meaning that we receive the schedule from New York. New York is the so-called scheduling ISO. So they do the calculation of the optimal schedule between the two ISOs.

So for New England, what we do is we calculate a so-called set of supply curves at its proxy bus, and then we provide those set of curves to New York ISO every 15 minutes. And these curves basically represent forecasted New England prices or New England marginal costs at different interchange levels. So in other words, we provide a marginal cost curve, saying that if we import or export this amount of megawatts, what would be a new England marginal price? And then New York ISO would take those supply curves that are generated by New England. And also, we're taking those CTS bids, those are price spread bids, and put them at the proxy bus in New York system and optimize their real-time dispatch with these CTS bids and New England supply curves to determine the optimal interchange level.

And once they calculate the optimal interchange level for every 15 minutes, they will pass back the interchange megawatts and the two ISOs will fix that optimal interchange level in the next 15 minutes, in the real-time dispatch of the next 15 minutes. So both ISOs do the five-minute real-time dispatch. So in other words, within 15 minutes, or roughly speaking, three real-time dispatch intervals will use the fixed optimal interchange level.

So I think this is just a graph to show this process. You can see the-- if we start with New England ISO, who will calculate the supply curves for the future intervals. And, of course, those supply curves come with the so-called gravity limit because interface has its limit due to various constraints.

Then we'll pass those supply curves to New York ISO. And at the same time, New York ISO will also collect all the CTS bids. And then New York ISO does its own kind of optimization, optimize over its own generators, internal congestion, and New England supply curves, and CTS bids to come up with the optimal interchange and pass back to New England.

So I'm not going to talk about all those sediment details. So you can always go to our website. We have a web page including all the details of this project.

So next slide, really, shows kind of this very simplified example of how it's done. So if you think about-- look at the blue curve, if you start from the right side to the left side, which means increase the westbound flow from New England to New York, so new England is-- think of it as a supplier to the New York. So you can see the marginal cost will go up right when New England export more. So this blue curve is generated by New England. And then New York, what it does is it has kind of its own generations and loads and transmissions. So you can think of they have owned their generation stack.

And then CTS adds additional cost because it's a spread of bids. They specify the transaction only when the there's a certain price spread. So it's basically, you add on the New England supply curve, on top of it, additional price spread.

So then what New York ISO does is, really, when it's scheduling optimization problem, it's trying to find out the intersection point between the black curve, which represents their own marginal cost, and then the green curve, which combines New England's marginal cost and the CTS cost. And the intersection point represents the optimal tie schedule.

So this slide talks about the performance of the CTS design. So the tariff does require our market monitoring to evaluate the performance of first and second years of implementation. So basically, the market monitoring find out that there is a efficiency improvement after the CTS implementation. And they estimated the improvement of about $2 million for the first year and then $4.8 million in the second year. And they also did a comparison with the so-called tie optimization, and they also have a optimal interchange. So tie optimization, as I mentioned, the only difference from CTS is that tie optimization, there is no interface bid. So it's purely a coordinate between the two ISOs, trying to find out the efficient schedule.

And the optimal interchange is doing one step further because as I mentioned, there is a latency issue. Even with the 15-minute schedule, there are still some kind of system condition change within 15 minutes. So this optimal interchange is after the fact, you do some kind of assuming that you know the exact system condition and the exact AOMPs. What would be the optimal tie schedule?

And then they try to-- we compared all these three different cases. And then I talk about two alternative designs. One is the tie optimization. As I mentioned, it's very similar to the CTS implemented today. So only difference is you don't see, actually, any interface bid.

It's really, we try to optimize New England, New York generation altogether. So New England will provide a generation stack and then New York will optimize it with its own generators to find out the optimal interchange.

So this slide is, mathematically, what really this tie optimization does. And if you see this, a little mess, but let me just very quickly explain what's going on here. So we think the joint dispatch problem as a benchmark problem. So think about if you have a super ISO organization that does the so-called joint dispatch of the both new England and New York system.

So it will minimize the total cost, right? New York and New England total cost and subject to New England constraint and New York constraint. And one and two here are New York balance constraint and New York transmission network constraint. And four and five are New England constraint. And three is just the limits for the interface between the two ISOs.

So now, mathematically, you can just reorganize this joint dispatch problem into a bilevel optimization problem. So on the lower level, you can actually just optimize the New England, minimize the total New England production cost subject to its own constraints. But in this optimization problem, you will treat the interchange between the New England and New York as a parameter.

So it's basically a parametric optimization problem. And what you get is a function of the New England cost as a function of the interchange. And then on New York, on the top, high-level problems of New York, ISO will optimize its own cost subject to its own constraint and then include a new England supply cost.

So then you can see how this translates to the previous figure, like why New England can calculate the supply cost as a function of the interchange and then give it to New York and how New York optimize it to get the optimal interchange. And CTS just add another cost of those spread bids into this optimization problem is very similar, so I'm not going to show here.

So another alternative design that was discussed during our design is so-called marginal equivalent method. So the motivation is that both CTS and optimization are built on the proxy bus model. As I showed in the previous slide, the way that you can actually decompose the joint dispatch problem into bilevel optimization problem is that we model the interchange in between the two ISOs as if those interchange as injection or withdrawal at a single proxy bus node.

So, of course, in reality, that interface is made of seven AC ties. It's not a single bus. So there's approximation involved in the network model is CTS or tie optimization approach. So that triggered us to consider a different approach called marginal equivalent.

And also, there's a latency, as I mentioned. Even with 15-minute scheduling, you introduce latency. So this marginal equivalent approach also tried to, actually, directly coordinate the real-time dispatch processes of these two ISOs. So I have some links if you want to know more details.

So the basic idea is coordinate each region's real-time dispatch through exchanging key information of marginal units and binding constraints. And it has a few theoretical kind of proven benefits. It's always convergence. It's very fast convergence, so I'm not going to that.

But at a high level, really what this marginal equivalent algorithm is try to do is, again, you think about joint dispatch problem as a benchmark problem that gives you the best or most efficient solution of the coordination. And then really, what we try to do is decompose that problem into a two-coordinate dispatch problem.

So kind of a naive starting point is you think about joint dispatch problem with including New England, New York variables and constraints, so we do some iterations. So first, you solve New England problem by fixing New York constraints and New York variables. And then you do-- on the New York side, you do New York optimization but fix the New England problem.

So that naive thought wouldn't lead to actually the optimal solution of the joint dispatch problem. So we dig a little bit into theoretical side and find out that actually, you do a little bit more than just optimize your own constraint and variable by including the marginal constraint-- marginal variables, and binding constraints of the other region.

That actually would-- simply doing that would lead to the joint dispatch problems optimal solution. So with that, the last page I have is a few key takeaways. So we did implement CTS between New England and New York, and our market monitoring has shown there's improved efficiency.

But however, there's still some unrealized benefit of the approach. One causes a latency and the other is a proxy approximation. And then I introduce two coordination schemes, maybe considered for future improvement. With that, that's all I have.

YONGHONG CHEN: Thank you very much for great presentation. We'll have the Q&A at the end of the panel. Please, submit your questions to the Q&A box.

The next speaker is the last speaker for this panel is Mr. Matthew Vos. He's the control room supervisor at ISO in Canada. And Mr. Vos will discuss the interconnected operation and real-time congestion management.

MATT VOS: OK. Can you guys see that slide deck OK? Perfect. Thank you. So thanks for the opportunity to come speak with everyone today. It's a real privilege. So as Yonghong mentioned, my name is Matt. Been at the IESO now for about 16 years.

Most of my time has been spent in and around shift operations. So I started out as an entry-level control room operator, worked my way through the different positions in the room, and ended up working as a shift manager as recently as last year. And I'm also the chair of the interchange distribution calculator steering committee. So that's the steering committee that provides oversight to the IDC, or that's that real-time tool that Tim mentioned that we utilize for real-time congestion relief.

So I've got a few slides I'm going to speak to you today and going to talk a little bit about the benefits of being interconnected, especially during extreme events. And then I'll talk a little bit about congestion management and how we handle things at the IESO.

So this slide just speaks to the IESO's role in Ontario. So we're the RC, the BA, and the TOP for the province. We essentially have two main roles. We're responsible for the reliability of the IESO-controlled grid, and we also facilitate Ontario's real-time electricity market.
So even though we're considered a non-market in the industry, we still do have a market. So we have a day ahead commitment process we run. We have an hourly pre-dispatch sequence that is responsible for refining our generator commitments, but also scheduling interchange. And then we have a real-time five-minute dispatch sequence, as well.
We've been undertaking a project for the last eight years since 2016 on renewing the IESO's electricity market. So that actually goes live early next year, so May 2025. So we're looking forward to that.
Just a little bit about the province. We have a lot of nuclear, we have a lot of hydroelectric, and wind and solar, and then we also have a little bit of gas, as well. So we stopped burning coal in 2014 in Ontario. So we're proud to say our grid is 93% emissions free.
And we have multiple tie lines with five different areas. So to the West, we have ties with Manitoba, Minnesota, and Michigan, all overseen by MISO. We have two separate interfaces with New York, and then we have multiple interfaces with hydro-Quebec. So I think everyone knows that HQ is their own interconnect, so we have DC ties that we use to buy and sell power between us and Quebec.
We also have the ability to segregate units in and out of the province or each province. So we can actually isolate generators in Ontario and switch them into Quebec and vice versa. And aside from our DC ties, that's the primary way that we buy and sell power between us and Quebec.
So a couple examples just to really highlight, especially from a real-time perspective, the benefits of being interconnected. This example is not a specific day but just a time period. So in the early 2000s, Ontario was pretty tight for energy. We had demands that were increasing quickly and some of the supply that we were building wasn't quite ready yet.
So we actually set our peak demand in 2006 at 27,000 megawatts. But for most of the early and mid-2000s, we were a net importer, especially during our peak periods. And it wasn't uncommon during our peaks to be importing about 4,000 megawatts from our neighbors. So just shy of 20% of our demand was being met with support from the interconnect. And if we weren't interconnected, it would have been a tough time for us to keep the lights on during that time period.
This is a bit of a unique event, but again, I think it really highlights the benefits of interconnected operations. So this is from July, early July of 2013. You can see that picture on the left. We had an incredible storm roll over downtown Toronto. So we got about 5 inches of rain in just under a two-hour period. So that's the same amount of rain that we would expect for the entire month of July.
Happened right at rush hour in the evening. So all the highways were shut down. You can see in that picture on the right, a lot of the commuter trains that people would take in the city were all shut down due to flooding. So there's all kinds of pictures like that of people being rescued from trains via boat. So pretty significant event.
But from a grid perspective, it was significant for us because the rain actually flooded the basements, a lot of the major transformer stations that supply downtown Toronto, especially in the West end of Toronto. And a lot of their relay buildings are in the basement. So all the DC equipment that's responsible for controlling all of the high-voltage equipment ended up shorting out.

And so what that actually meant was in the West end of the city, we ended up losing 25 230-kV circuits in a matter of minutes, and we lost 4,000 megawatts of load. So it was the second largest load loss that Ontario experienced, only behind the 2003 blackout.

So you can imagine Ontario was chugging along. Our load generation was balanced. And then as soon as you lose 4,000 megawatts, now Ontario is in an over-generated state. So all of those additional megawatts that we're generating get pushed out on the ties. So we pushed out about 3,800 megawatts unexpectedly to our neighbors.

So after we had the contingency, we immediately reached out to our neighbors to let them know that we had had an issue, and that we were going to need their support for a short period of time until we could get that load generation balance back in line. So had we been islanded or had minimal interconnection lines, this event would have been much more significant for us. But because we were interconnected and our neighbors were there to help us out, we were able to lean on the ties a little bit.

And the interconnect essentially helped absorb that large frequency excursion that we would have expected. So during this event, we lost 4,000 megawatts, and the interconnection frequency moved from 60 hertz to 60.07 hertz, so 7/100 of a hertz for a 4,000 megawatt change. So again, it really speaks to just the size of the interconnect and the value that it provides being interconnected with our neighbors.

Another event we had in 2019, we experienced, in very short order, the simultaneous loss of four 500 megawatt nuclear units, so about 2,000 megawatt gen loss. IESO is part of NPCC. NPCC is our regional reliability organization, and we're part of a program called SAR, which is simultaneous activation of 10-minute OR.

So all of the NPCC areas participate. HQ does not because they're not part of the Eastern interconnection. But PJM is also part of this program, as well. And basically, the way it works is every area carries their own 10-minute OR requirement, but when someone has a contingency, they can basically call on the NPCC neighbors for support, and we essentially work together to collectively restore the load generation balance. So we respond to that contingency together.

So in this event, we lost 2,000 megawatts of generation. We were able to get support from our neighbors, and they supported, bringing up about 1,000 megawatts of generation until we could get things back in line and restore our load gen balance. So another great example of the interconnect really working together, especially during contingency events.

And the last one that I think is probably still fresh in everyone's mind is winter storm Elliot. So significant cold snap we had. It was Christmas of 2022, and Ontario was fortunate in the sense that a lot of our resource fleet performed well. A lot of our gas generators perform winterization ahead of our cold winters. So we had excess energy available, and we were a net exporter of about 4,000 megawatts.

And you can see in the picture on the right, we were selling heavy to MISO via Michigan and new York, but those megawatts were actually wheeling through New York and Michigan and heading South down to PJM, who was having a tough issue with unit starts and-- excuse me, and d rates and whatnot.

And for a period of time, PJM was also selling down to the South, as well, down to TVA and Baker. So it really highlighted the ability of the interconnect to wheel megawatts from one area that had extra energy to areas that needed the energy the most.

And you can see, we were also selling to HQ, but all those megawatts were wheeling around down to New England. So again, just a good example of the interconnect working together, especially during these difficult stress system conditions.

So there's no question that being interconnected provides a lot of value. One of the challenges you have sometimes when you are interconnected is it can lead to unscheduled loop flows through your system. So the most common type of loop flows that we experience in Ontario is something called Lake Erie Circulation or LEC. So these flows impact Ontario, but they also impact MISO and PJM and New York, as well.

So Lake Erie circulation is essentially somewhat self-explanatory. It's in the name. It's circulating megawatts that basically flow around Lake Erie. So there isn't one specific thing that can cause circulation. It's really a collection of different variables among the four areas that are around the Lake. So it's really just a function of generation and load patterns and transaction schedules between areas, again, that can collectively cause circulation. So sometimes, circulation is not an issue. It can be low. Other times, it can be as high as 2,000 megawatts.

So years ago, especially in the mid to early 2000s, Lake Erie circulation was consistently high. And so there was all kinds of TLRs that were getting issued. Areas would have to actually hold down their schedules or limit the amount that they can basically flow between each area to help constrain circulation. So it was a challenge for a number of years.

And then a project came in the Ontario-Michigan pars that really changed circulation quite a bit. And then those pars came into service in 2012.

So just to highlight, the Ontario-Michigan pars are basically phase angle regulators. And for those of you who know, a par is essentially the ability you can tap on these big transformers, adjust the phase angle, and essentially control the megawatt flow through parts of the system.

So each of our four tie lines on the Michigan interface has a par in series. So we can essentially control that interface flow now. The pars were first introduced in late '98. They didn't come into service until 2012. So there was a number of equipment issues that delayed the in-service date for the pars.

But there was also some interesting regulatory discussions that came up that I thought were relevant for this group. And one of the questions that came up was, should the ratepayers in Ontario or, let's say, Michigan, have to bear the cost of putting in a piece of equipment that's going to provide a much broader benefit to other areas with respect to controlling circulation?

So as I mentioned, circulation essentially impacts all four areas around the Lake. So should Michigan and Ontario pay for something that benefits everyone around the lake, essentially? So there was a number of discussions that took place around that also sort of slowed things down.

But with respect to the Ontario-Michigan interface, when we operate that interface, we try and get ourselves to flow equal to schedule as much as we can. And we consider ourselves to be in what we call regulate mode when we're within plus or minus 200 megawatts of flow equaling schedule.

So just to highlight the difference between pre-par days and post-par days, before the pars came into service, we were in non-regulate-- or regulate mode, excuse me, 43% of the time. So a different way to think about that number is 57% of the time, we had loop flows through Ontario, New York, PJM, MISO that were greater than 200mw. So that's pretty consistent circulation we were seeing.

Post-pars, there were some studies that were done just to highlight how beneficial the pars have been. And it highlighted that we were in regulate mode around just over 95% of the time. So huge improvement from a congestion management perspective, with the ability to control circulation and not see those unscheduled loop flows.

But what that means is the remaining just under 5% of the time, sometimes, we'll actually run out of tap room. So those pars only have a certain range that they can operate in. And if circulation is high enough, we'll actually run out of tap room, and we'll still see Lake Erie circulation that's higher than 200 megawatt– excuse me, 200 megawatts.

So once that happens, we declare the interface into what we call non-regulate mode. And when we go into non-regulate mode, if an area anywhere around the lake is seeing circulation that's impacting their flow gate, this is when they can utilize that tool that Tim was talking about earlier called the IDC or the interchange distribution calculator.

So what it essentially is, is it has a model of the Eastern interconnection, and operators can actually utilize this tool in real time to see who is contributing to the congestion they're seeing on their system. And then it also allows them the ability to issue a TLR, which essentially issues curtailments to neighboring areas. And those curtailments can be interchanged curtailments or it can be agenda load redispatch. So essentially, an area redispatching generation in their footprint to help reduce congestion on a different part of the system. And just to highlight an example of what the tool might show you, and this is just a hypothetical example, so I'm not picking on MISO or PJM here.

But let's say Ontario or New York was experiencing circulation through their area, and MISO was selling PJM 2,000 megawatts. The tool would look at, basically, the topology of the system and say, OK, on paper, MISO is supposed to be selling PJM 2,000 megawatts from MISO directly to PJM. But in reality, 1,800 megawatts of that transfer is actually flowing across the MISO to PJM interface. The other 200 megawatts is basically looping around Lake Erie, through Ontario, through New York, and eventually into PJM.

So the tool would actually identify those transactions as a potential option to issue a curtailment to basically help provide relief in a neighboring area. So again, the tool looks at the collection of interchange schedules and generation patterns to come up with its curtailment options, but this is just one example. And just to highlight the IDC. So this tool was first created in 1998, when deregulation was starting to take effect, and all the areas agreed we needed some consistent tool that everyone could use to basically help manage congestion they were seeing on their system. So the tool was revamped in 2022. So that's what Tim was talking about, as well. We call it PFV. And the NAESB standards were revised, as well.

It's important to note, though, that even though the tool came into service in 2022, this project started in 2009. So again, it took a number of years to roll this out. And things like this are not easy. You can imagine you've got all these different areas with different market designs, different internal concerns, different curtailment rules that they have. So trying to create a uniform set of curtailment standards and rules around how this tool works among a bunch of different areas with different concerns is always challenging.

So it took a number of years for everyone to get on the same page and agree on how we want to roll this out. So it took some time, but definitely, we're seeing more accurate results in the new tool, and we're seeing more fair or consistent calculations and curtailment rules for everybody.

So the IDC remains an effective tool. Definitely still has some limitations, though. So one of the challenges right now is the IDC is not forward-looking. So it currently looks at the current hour, so the hour we're in and then the immediate next hour, but it doesn't have data for, say, the rest of today. So as an operator, it's challenging to try and figure out when you might experience congestion because there are so many moving parts sometimes to someone experiencing congestion on their system.

Right now, the IDC looks at one-hour increments, so it just looks at individual one-hour blocks. We're starting to have some discussions around, is that granular enough? Everyone's seeing more variability on their system now, so maybe we need the tool to start looking at 15-minute windows to really capture the constant changes we're seeing on the system.

And then the other limitation is it is still a reliability-based tool. So there's not a lot of real-time market info available in it. So that's one limitation, as well.

So just to summarize, again, can't overstate this enough, especially from a real-time perspective, being interconnected provides a significant amount of benefit. The Eastern interconnection is essentially one 700,000 MVA big machine. And so being a part of that provides a lot of benefits around synchronous inertia and the ability to support your neighbors or receive support from your neighbors.

So there's reliability benefits. There's also market benefits to help smooth out any fluctuations areas might see on their system. That's becoming more relevant now as we're retiring more conventional resources, and we're seeing more energy-limited resources, like storage, and wind, and solar. So having the ability to help smooth out those changes, not only from a reliability perspective but a market perspective, is incredibly beneficial.

And then my last bullet is really just around congestion management. So as I mentioned, I'm part of the IDC steering committee. We constantly meet, and we're constantly working on revising and enhancing real-time condition management tools or the IDC. So that's something that we will continue to do in the future. That's all I have, so I'll pass it back to you here, Yonghong.

YONGHONG CHEN: Yep. Thank you very much. Thank you for all these great presentations from our panelists. We're grateful to have with us three experts from Europe to share their insights on the European experience with multi-region market covering operations.

First, we invite Mr. Pietro Rabassi the executive vice president at Nord Pool. He will introduce the pole markets in Europe. Pietro, the floor is yours.

PIETRO RABASSI: Thank you very much. Can you hear me?

YONGHONG CHEN: Yes.

PIETRO RABASSI: Excellent. Very good. So thanks very much for the invitation. I think it's a great opportunity to discuss about our setup that we have in Europe and how the experience has been. What I want to do is to walk everybody through, basically, what the setup is in Europe, what we have in terms of what the Nord Pool experience has been, what Nord Pool is, and actually, what the trends are, and what we see are the advantages of having a market also related to the recent energy crisis that Europe faced.

You can see my screen, right? Good. OK. So first of all, I want to say what Nord Pool is. Maybe some of you don't know, but we have been around actually since the early '90s when the energy markets had been liberalized in Europe, and actually, there has been the unbundling of the different segments of the energy chain. And so the markets have become kind of their own entity in a sense.

And so let me go to this slide. We have-- oops, sorry. Yeah, there we are. In 1996, we created the world's first international power market day ahead. And in 1999, it was the first intraday, international intraday market. The action later became the target model at European level. And today, what we can say is that Europe is integrated across all the EU countries with that model, which is a great achievement, and both from the energy perspective, economic, and political, and policy perspective.

Now, if I go back to this slide here, as you can see, so we are present in various countries across Europe. The highlight is in green. And we are also servicing power markets in the blue ones and also doing any type of activity related to energy and power markets across Europe and across the world.

So just to, a little bit, set the stage, what we experience in Europe is a steep increase of renewable energy sources, specifically intermittent renewables, so wind and photovoltaic, for many years now. And you can see on this trajectory here that we have that share, about the share of renewables, has been increasing over the years and over the past decade to very high numbers.

And according to also the EU targets, by 2030, we will be having Europe probably 57% of renewables, at least, and 30% of intermittent renewables. Germany has been one of the, I would say, four frontrunners in this, and with a power generation from renewable energy sources of over 40%, nearly 50% last year, and with very ambitious goals to achieve a carbon-neutral generation of electricity by 20-- hopefully, in the next years and maybe also in 2030. We don't know.

So what does that mean in terms of trends in the market? So having more renewables and more intermittent renewables gives the need to be able to be active in the power markets close to delivery. That is because the power of-- the weather forecasts change, and they become more reliable the more you move closer to delivery.

The power markets have become more and more complex, with different products, hourly products, quarterly products, different auctions, continuous market. So humans cannot cope with that complexity anymore. So we need-- we have witnessed the presence of more and more APIs. So that means the use of algorithms and/or automation.

And then in a normal situation, renewables drive prices down. And then if you are a business, you want to keep your margins stable, you need also to cut costs. So that means that in the last years, we have been seeing a lot of cost-cutting exercises and actually being cost-conscious is the future of the energy sector in Europe.

And also, we have seen the need for what we call the decentralized markets because we have more and more decentralized generation of electricity with, as I mentioned, photovoltaic wind, more electric vehicles, batteries. So there are certain problems that need to be solved at more local level, kind of DSO level, distribution level. And there are more and more concepts and, actually, businesses trying to take care of these decentralized flexibility markets.

And, of course, last point-- I mean, the second last point is also something related to the energy crisis, the flat fee pricing needs. But also, the last point is the fact that we have more and more renewables, more players dealing with renewables, with basically changing needs and new business needs. So we, as market operator, we need to be active and understand these business needs and try to serve in the best way that we can.

In Europe, Cosimo will speak about this, we have more and more integration, yes, from all fronts, continuous market of the day ahead markets. Well, the intraday auctions, which will be launched in Europe in two days from now, so it's very big news. We have more and more interconnections and cables connecting the various areas and also more and more decentralized markets, as I mentioned.

And all of this integration is the benefits of consumers. We estimate that more than 30 billion euros per year are actually the benefits of the power market integration in Europe to the end consumer. And also, competition, of course, is to the benefit of market participants and consumers.

So this is why we believe that the concept of sharing of order books, basically which means that in all the markets where there is more than one power exchange needs to be enforced. And that will happen when the new electricity regulation comes into force in the next few weeks across Europe.

I will skip this one. Now, what is the role of the market in the energy transition? This is an interesting, yes, kind of aspect because the markets do contribute to the energy transition. But how?

The first point of the five is that the merit order, which is basically the way that the-- many of you know this concept, the way that the electricity sources are used is basically by taking the least expensive sources first. And that concept actually promotes carbon-free electricity production because if you take the marginal costs, the renewables tend to be-- and nuclear tend to be the sources that have the lowest marginal cost. So basically, you incentivize those sources to be used first.

Marginal pricing also, that is for the production but also for generation. It's basically to invest in generation is an incentive because, of course, when you have prices and then you still have fossil-fueled power plants in the mix, you give an incentive with this margin between the clearing price and the marginal cost of production of low-carbon intensive plants, you give this margin to those renewable generators that actually have all the incentive to invest.

Also, the use of interconnectors favors carbon-free generation. And that is because the idea is that you interconnect the different areas. And when, basically, you do that, you make sure that the countries do not rely on themselves, but they can actually rely on their neighbors.

And that means that even if the source is on the other side of the border, can be also between Finland and Portugal, for instance, if there is enough cross-border capacity, and there is a maximization of the use of low-carbon or carbon-free generation. So if there is, for instance, a surplus of wind in some areas of Europe, if there is enough cross-border capacity and the interconnectors, actually, that can be compensated by higher use in other parts of Europe.

Then the fourth advantage that-- the fourth point where the market plays an important role in the energy transition is that the intraday markets, which are continuous markets, in certain countries that are operating until delivery of electricity, actually allow the renewables to be managed on a 24/7 basis, basically all the time. And that is an important aspect because, as I mentioned at the beginning, the weather forecasts become more reliable the more you move closer to delivery of electricity.

And I think it's an important aspect to mention, and having systems that can cope with that aspect and of the trading activity of the markets and having very well-performing intraday markets is key to be able to then allow for this energy transition and the role of the intraday markets. We can see that in the sense that at Nord Pool, if we take this first quarter, we've had 100% increase in our year on year volumes in the intraday markets.

So there's a booming activity that goes hand in hand with the wider use-- the wider, sorry, installations of electricity coming from carbon-free, and specifically the renewable energy sources that goes hand in hand with the use of the intraday market.

Also, the fifth aspect I wanted to mention is the fact that if there is the use of a power market, so the more the power market the EU is used, so the more-- the higher the price transparency and the higher the consumer empowerment through demand response.

And that is because if you have basically all generation, the more generation you have, the more consumption into the marketplace and not bilaterally in the OTC, over-the-counter. Basically, you maximize the reliability and the transparency of the price signal.

And this is why we, as Nord Pool, we really want to lower the barriers to enter the market. We want also the smaller market participants to be active with us. We have different concepts that allow for small-market participants to be part of the market and be active directly in the markets.
So that means that by incentivizing the smaller-market participants to be part of it, gives a more kind of reliable price signals. And also, if-- so the market signals, market price signals, trickle down to the consumer through the-- I would say the intelligent technologies like smart meters, smart devices.
Then actually, there is an effective load management and demand response activity that can take place as long as, of course, there are also the price incentives, right price incentives, in place because as you may know, across Europe, in certain countries, there is-- so the component coming from the wholesale market price in the final consumer energy bill is only a small percentage. So all the rest is taxes and levies. And if that is the case, then, of course, the price signal is also a small part of that end price bill. But in some other countries, actually, the final bill is very much linked to the wholesale market price signal.
Yes. So just a few words on how we see the future power market design. We have an introduction of, as I mentioned, into the auctions, the 15-minute regularities in Europe. We still have actually differences. We have certain areas, certain countries with 15, others with 30, and many with 60 minutes. So that is also something which is coming into being in the next months.
But also, there is a kind of a high level type of view that we should take is the fact that in 2022, to cope with the energy crisis, we've introduced emergency measures. And those emergency measures actually have coped with the short-term effects of the crisis.
There has been also a very intense activity when it comes to the electricity market design review, which was a package that included different legislative measures, and including the review of the electricity regulation, the electricity directives in Europe and the European Union that foresee various changes in the market. So first of all, it was also seen that-- it was accepted that the market, and specifically the spot markets, are not broken, but actually, some changes had to be implemented.
And here, I just name a few of the changes that have been foreseen by the electricity market design review. Then we have actually the next step, which is after this comes into being, what is next? Well, we'll have to think about different other aspects when it comes to short term and long term market improvements.
We have also to think about bidding zone reviews. We know that if you have more and more renewables, actually, there is a problem of congestion and redispatch. We talked about the decentralized flexibility market that can be a solution. But also, reviewing the bidding zones is a way to cope with those congestions.
And also, you can build, of course, new interconnectors, new cables. But we all know the nimby problem, not in my backyard problem that makes overground interconnections very difficult to implement and underground ones very, very costly.
Yes. So the electricity market design reform, as I mentioned, is expected to enter into force when it comes to electricity regulation by mid to end of this month. So we are definitely looking good from that perspective, and we have different concepts that have been include, as I mentioned, through the sharing of order books for day ahead and intraday.

Some points about the capacity mechanisms, the electricity price signals, and contracts that can be used, peak shaving products, and other concepts that actually have been included in this very important reform. Having said this, I want to thank everybody for having listened to me. I kept it to 20 minutes.

And yeah, if there is any question, I'm here, and I'm happy to conversate, debate about this very interesting topic, which is the electricity markets in Europe and the energy transition. Thank you very much.

YONGHONG CHEN: Thank you very much, Pietro. It's a great overview of the EU market, and we'll have the Q&A at the end. Next, let's probably go to the next panel is the professor Anthony Papavasiliou. Anthony is from the school of electrical and computer engineering at the National Technical University of Athens. He's an expert in both the US and EU market, and he will discuss the effectiveness and the technical challenges of zonal market clearing for congestion management.

ANTHONY PAPAVASILIOU: Thank you, Yonghong, for the introduction, and thanks, everyone, for your time today. I will first try and share my screen. Is it OK now. Can you see my presentation fine?

YONGHONG CHEN: Yes.

ANTHONY PAPAVASILIOU: Great. All right. So, yeah, thank you very much for the opportunity to talk at this very interesting panel. So I'm going to talk about the effectiveness and technical challenges of zonal market clearing for congestion management.

And as Yonghong mentioned, I am currently an assistant professor at the department of electrical and computer engineering at the National technical University of Athens in Greece. And before that, as of from 2013 until 2022, I was an associate professor at the Center for Operations Research at UCLouvain in Belgium.

But exposure to the US comes from the fact that I did my PhD at UC Berkeley in the department of industrial engineering and operations research. The team that I currently lead consists of four PhDs and four postdocs who work on the application of operations research in electricity market design and power system operations, currently funded by the ICEBERG ERC starting grant.

In addition to academic activity in our group, we have engagement with industry. So within the context of SDAC and ACER, as far as Europe is concerned, and based on these experiences that I've used for creating the material for today, I've worked on the EUPHEMIA labs, the co-optimization of energy and reserves and topics of non-uniform pricing, the implementation of scarcity pricing, and the dynamic dimensioning in Belgium, the implementation of scarcity pricing and reserve dimensioning on networks in Sweden, the analysis of balancing markets under the target model, scarcity pricing, and pricing in non-interconnected islands in Greece, and the comparison of CRMs and scarcity pricing for German think tanks.

Also, a bit out of European Union, at the UK on the optimization of Energy and reserves in UK, balancing capacity markets, and internationally in Colombia, and the analysis of transition from self dispatch to central dispatch, the prototyping of the power exchange algorithm in India, and the review of the pricing algorithm in Israel.

So first part of the presentation is targeted at commenting on the setup of zonal pricing in Europe and how we coordinate networks and inter-regional access between European countries. So some high-level information about the European market. European system installed capacity is approximately currently equal to 1,000 gigawatts.

The annual day-ahead traded volumes in the European day-ahead market amount to 1,683 terawatt hours. So quite an expansive, geographically expansive, system.
There are three major frames for coordination of energy trading, in particular, the day-ahead market referred to as the single day-ahead coupling, SDAC, that was already discussed by previous panelists, the intraday market, or single intraday coupling, SIDC, and the balancing platforms. This includes a platform for imbalance netting, abbreviated IGCC, a platform for automatic frequency restoration reserve, which is abbreviated the PICASSO platform, and a platform for manual frequency restoration reserve, which is abbreviated MARI.
One thing that I think is important to say about Europe and how this has all come about is that there is legal coordination. So there is EU-wide regulation that is binding. It's guidelines largely, but specific enough to give member states an idea of where they should go.
So examples of such EU-wide legislation are the capacity allocation and congestion management regulation, abbreviated CACM, the electricity balancing guideline, abbreviated EBGL, the system operation guideline, abbreviated SOGL, and the electricity regulation. So when I was thinking of, how do we coordinate in Europe, I was able to isolate the boxes that are indicated in the bottom of the slide, and I'm going to talk about each of them in more detail in the next slides.
But some high-level comments. One is that we have a mostly portfolio-based market design in Europe. I'm going to talk about that more later. And the fact that we use zonal network models from day-ahead to intraday, all the way to real time.
Major steps of inter-regional coordination, in my view, include longterm aspects, in particular, the bidding zone configuration and bidding zone review, the process of building the network models that go into the market clearing, the head energy market, and then the actual clearing of the day-ahead market, what happens after the day-ahead market, which is nominations and congestion management, and then moving within the day, the intraday operations, and the adjustment of the market network models as we approach real time, and cross-border balancing, which also now is becoming-- it's a cross-border balancing. It's not anymore a national activity.
So I'm going to talk about each of these boxes in some more detail, hopefully giving you some more precise views on how things are done in Europe and maybe some ideas of what that could be useful for the US context. And so starting from the long term, the bidding zone configuration, this is the result of building zone review, which is what I consider at least a politically difficult process of deciding which physical nodes are attributed to which zones.
This hotspot data is thrown to the hands of ACER, the Agency for the Cooperation of Energy Regulators, which is an agency of the European Union. And it's something that doesn't take place frequently. It's triggered by articles 32 to 34 of CACM and article 14 of the electricity regulation.
And in practice, it's been done once in 2018, where there was no outcome because the methodology was considered inadequate and one big zone review that's ongoing. The reason these things are tricky is because splitting countries into zones means higher prices, maybe for parts of the country and lower prices for another, or higher prices for one country and lower price for another. So you can imagine that this can be thorny.
Then next step, this is pre-day-ahead, is the computation of the head market network models. We use two principal network models as input to our market clearing software in Europe. These are the

transportation model, where we essentially ignore [INAUDIBLE] costs and assume that we can directly control flows on lines.

For this model, we need some parameters that are exogenously computed, which are the available transmission capacities. And then there's a flow-based model, which you can think of as a zonal approximation of power transfer distribution factors. For a flow-based model, you need to compute a flow-based polytope, which is essentially the feasible region of net injections in different bidding zones. As long as you're within this polytope, you have feasible exchanges of energy between different bidding zones and to compute these polytopes, which are published in JAO.

So these are publicly available. You need to estimate zonal power transfer distribution factors, where you have to assume a base case of whether the system will be operating and then quantify generation shift keys. And you also have to compute remaining available margins on every critical network element. And here, we can also account for contingencies. So critical network elements subject to contingencies can also be part of this process. The polytopes that are published in JAO are anonymous in the sense that it's just a linear inequality without telling you if that's a line in some specific area of a specific country. Now, this all is a tricky process because you have to approximate physical reality with aggregated information. For instance, for flow-based polytopes, you need to estimate rams and generation shift keys. And this is circular because this calculation affects the base case, but the base case is assumed to make this calculation, and that creates problems. So this is not an easy process, overall, and approximations are inevitable.

Once these polytopes are computed, they are input into EUPHEMIA. EUPHEMIA is the algorithm that clears the pan-European day-ahead energy market and the pan-European network. So it's a co-optimization of energy allocations and transmission access. And the prices that are produced by the algorithm are accounting for zonal network constraints, as well as the merit order of each country. It's also, I should mention, a success story of my former group at UCLouvain since the brains behind EUPHEMIA have largely-- the innovations have come largely from academics and experts who joined N-SIDE, which is a spinoff of core in UCLouvain. The overall structure of the algorithm is presented in the right part of the figure here. It's essentially a branch and cut algorithm, where we match orders of continuous type, as well as, yes, take, take-it-or-leave-it offers.

And then after we do this matching, we look for prices that are compatible with idiosyncratic EU pricing rules that have to do with non-convexities. The overall problem is extremely difficult. It's a mixed integer quadratic program subject to complementarity constraints, and this branch and cut algorithm tries to tackle that. But the focus of today's not to talk about pricing non-convexities. It's more to talk about how this method coordinates between regions. And the way it does is through zonal market clearing prices. Now, once we lock in the net positions of the different market participants, then the portfolio owners, recall, I mentioned earlier, we have portfolios in Europe, can walk out of the day-ahead energy and the day-ahead reserve auctions, and they can decide how to deliver this energy and this reserve by nominating individual units within their portfolios to match their financial positions. This process is called nomination.

Each portfolio owner communicates which assets they want to run to the transmission system operator after the day-ahead energy market clears. And then the TSO needs to check if physical constraints can be satisfied. And if they cannot be, we need to resort to re-dispatch.

Re-dispatch often occurs within a bidding zone, and the idea is to do INC-DEC adjustments to restore network feasibility. These INC-DEC adjustments are typically paid as bid, although each TSO has the freedom to set up things nationally for this re-dispatch process. And the bids are settled using either cost-based-- they're generated either using cost-based estimates or market-based offers.

Market-based means the asset owner can decide what they believe is their incremental cost. And if you go with the market-based option, you create wonderful opportunities for INC-DEC gaming that have been exploited in various member states in the Europe. And just as a reminder of the cold reality of INC-DEC gaming, I'm showing you the license plates of the old Lexus of Shmuel Oren, my advisor in California, which he bought around the time that INC-DEC gaming and a number of other factors collapsed the California market in the crisis of 2001.

And then after we do the re-dispatch nominations, we start moving very close to real time. So here, we enter the domain of intraday markets and balancing platforms. So the intraday market consists of two parts. There's the intraday auction and then continuous intraday trading up to a bit less than an hour before real time.

And for the balancing time frame, we have transportation-based models, where ATCs are adapted to the real-time position of networks. And this is now very tricky because if you have time to correct things before real time, in real time, you're threatening operational security.

This idea that was presented earlier by our ISO New England colleague is a very interesting approach. We call it hierarchical residual supply functions in work that we've done with Statnett, the Norwegian TSO. But instead, Statnett ended up-- because it's highly meshed system, and you have this multi-dimensional effects that I talked about in my Q&A, they have opted instead for a process called bid filtering.

What is the idea of bid filtering is a bit graphically depicted here. In the rows of this matrix, you have different offers that could be activated in real time. In the columns, you have different network elements in the five different zones of Norway. And the more red the box, the more likely it is that if you activate this resource, it will likely congest that network element.

So if there is any red elements in this line, then you want to filter that bid and not even allow it to enter the real-time market, which means that in order to safeguard security, because of the zonal models, we sacrifice to a certain extent economic efficiency. Then there are challenges with zonal. It's working in Europe, but the challenges are well known and documented.

I mentioned some here, short-term inefficiencies related to unit commitment. Germany has reported congestion management costs, redispatch costs in the order of billion euro per year. And this is, to some extent, related to the fact that you're turning on and off units in places that you're not supposed to and then turning on other units to create counter flows.

There is also the question of sending longterm signals for appropriate investment. So you cannot tell where you should build the plant in Germany if you cannot have a separate price in the North and the South. And the North and the South are very different because the North is flooding with renewables and the loads are in the South.

There's challenges related to INC-DEC gaming, and there is the threatening of operational security in real time that I mentioned in the previous slide. And also, in the figure in the right, I'm showing you a textbook application of INC-DEC gaming, where you essentially have a market schedule, which is the blue line in the day-ahead that violates the physical limit of a line, which is the orange in this figure.

And all of a sudden, the asset owners behind the binding constraint feel that their marginal cost is minus 30 euros per megawatt hour because they know they will be decked, and they will be paid to be decked because they're bidding negative so that they get paid for actually delivering zero megawatt hours to the system. So this is a kind of persistent challenge.

Then a few comments on nodal versus zonal, the debate that's ongoing in Europe. This has been going on as discussion for years. Some of the criticisms that you would hear about nodal pricing relate to institutional compatibility. So the fact that transmission system operators have to exchange sensitive information about national infrastructure and the fact that the existing regime can keep costs low for consumers in certain member states.

But the counter-argument is that the fact that some consumers would prefer to pay a low price doesn't mean that we need to socialize transmission access costs. In terms of implementation, complexity arguments you might hear might relate to the fact that it's technologically too complex to do nodal pricing, and that we like the portfolio setting that we currently have.

On the other hand, the implementations in the US prove that it is technically feasible from a computational standpoint and an institutional making it happen close to real time standpoint. And also, there are also arguments in favor of unit-based, for example, better scheduling and market monitoring.

Criticism related to market power. So you are, by doing nodal pricing, geographically splitting the market, and you lead to firms with a dominant position. On the other hand, just ignoring the real physics of the network doesn't mean that the firm will be in a less good position to exert its market power and all designs are exposed to market power.

There's an argument of cash transfers. So with zonal pricing, you get the same efficient outcome, but with less money transferred from hand to hand. But this assumes that people continue bidding truthfully, even though the design induces them to not bid truthfully. There is an argument of non-intuitive price behavior, but that argument relies on falsely generalizing the intuition that applies to transportation networks in a world where Kirchhoff's laws apply.

And there's an argument of risk management and liquidity that there are too many pairs of nodes, and it's difficult to hedge against thousands of pairs of locations. To which Hogan counters the idea of contract networks with hubs and spokes that try and absorb a lot of the spatial correlations in the market.

And the last part of my presentation, I would like to focus in on reserve, and I'll be done shortly. So Yonghong raise the question about consistent definition of reserve products in Europe. So a few comments on this.

We have day-ahead energy markets in Europe that are integrated, but day-ahead reserve markets that are not, and they're cleared actually typically before day-ahead energy markets. The power exchanges clear the energy markets. The TSOs typically clear the day-ahead reserve markets. And each national TSO can design day-ahead or other forward reserve markets as they see fit.

Nevertheless, there is currently a push in the EU legislation, in particular article 40 of EBGL, for integrating the day-ahead trading of energy reserve in a single auction. In fact, our team recently concluded a study that shows that the economic benefits of this can rise to up to 1 billion euro per year for the entire European area because of coordination efficiencies in accounting simultaneously for energy and reserve.

As I mentioned, typically, reserve markets are conducted before the day-ahead energy markets. And although the commitment of reserve capacity is not integrated between Europe, the activation of this in the form of balancing energy is. There is pan-European platform for activation of FCR, AFRR, which is automatically controlled and the set point changes every 4 seconds, MFRR, where it's all manually controlled and full activation is within a few minutes, and restoration reserve.

So these are standardized product definitions, and the way that one is activated after the other is depicted in this figure here. So we have these activation platforms that deal essentially with real-time energy, but what is also interesting about the European design is we forgot to put in place a real-time market for reserve, although we have day-ahead markets for reserve.

And this makes scarcity pricing based on operating reserve demand curves a very difficult discussion. So here are graphically depicted day-ahead European market, the real-time European market. And although the two should be essentially following the same blueprint, note that we totally forgot to design a real-time market for reserve in Europe, although we do trade real-time energy, whereas we do trade reserve in the day-ahead markets.

And then one last comment on reserve deliverability. The question here is, if you are trading reserve in the day-ahead, how do you make sure that it can be delivered where you actually promised it? This is called the deterministic requirement in EU jargon, and it's a computationally tough problem because you have to worry about when you're matching reserve, the fact that the TSO has the option of activating zero megawatts of that reserve, the full amount of match reserve, or anything in between.

And that can be a computationally challenging problem, which you can tackle, nevertheless, with concepts based on inscribing boxes in polytopes. That's something that's been prototyped in EUPHEMIA and a proof of concept has been shown. And if you want to think of the whole thing graphically, when you're clearing day-ahead energy, you're picking a point in this net injection space, but when you're matching reserve, you're also on top of that, picking the red polytope that still has to land within the bigger black polytope.

So now you're choosing a shape on top of a point, and that's computationally challenging. With that, I would like to thank you for your attention, and look forward to the discussion in the Q&A.

YONGHONG CHEN: Thank you very much, Anthony. It's was a great presentation. So, Cosimo, can you try your audio, see if we can hear you?

COSIMO: OK, can you hear me now?

YONGHONG CHEN: Yes. Great.

COSIMO: OK, perfect. Thank you so much. Thank you so much, first of all, for inviting me. I think that the technical problem we had proved being useful because probably many of the concepts already introduced by Anthony can pave the way to my presentation, which will be only a verbal one, because I do not want to enter into too technical content.

I would like rather more to illustrate to you one line of interpretation about why the European market is so different from the standard model basically applied in the US, which has been the logic for its evolution until now and what could be said for the next future.

I want to clarify here that I'm currently here, not speaking neither in my role of representative of the Italian [INAUDIBLE] exchange nor of the European market capping. I have obviously the experience to that, but I'm talking purely representing a personal point of view here.

Let's start with, say, from a very simple and outstanding fact already illustrated by Anthony. The EU spot market, my focus would be on the day-ahead and intraday market, so the energy market, is, by far, the biggest, but only the only fully integrated one at the continental level worldwide. And this is happening,

strange to say, in the absence of such a strong political precondition like you have in the US. European states are not so united as the United States.
We do not have one single ISO operating the market for everybody. But we are able to manage one market, which is covering 27 countries, reach 2,000 kilowatt hours per year added on top, they added intraday, and being jointly operated by 17, we call them NEMOs, nominated electricity market operators. These are the power exchanges tasked with running the market, and 32 transmission system operators, which is apparently a mess.
And there is not even one single place, one single instance, where the market is operated. All those NEMOs, if they want, a subset of them, indeed, have the chance to run the single algorithm. This is single, and they do it on a rotational basis for a set of reasons.
And this is working. So this is the point. The second point for this is that we have, with respect to US approach, apparently simplified market design. As Anthony said, this is by no means saying that our algorithms are naive. Not at all. But the market design apparently is simpler. I said there is no one ISO but many NEMOs and many TSOs.
We do not have nodal pricing, but zonal pricing, where usually, zones represent member states. In some cases, Italy is one. Norway and Sweden are the two cases. The bidding zones are the countries within several bidding zones, but typically, bidding zones are member states.
We do not have, usually, unit bidding, rather, portfolio bidding. So you offer energy in France, and only later on, as described by Anthony, you nominate where this sold energy has been actually assigned. We have also a simpler, for certain aspects, bidding structure.
We do not have engineering curves with startup, ramp rates, and so on. We have simple bids or sophisticated block bids, but more of a commercial flavor than a technical one. We have a day-ahead market and a separate intraday market, running on continuous trading until now. And starting from two days in the future, we will have also auctions for the intraday, three separate auctions.
But we have no coupling of the real-time markets. These are completely managed by TSOs until now. So this perfect integration is dealing only with the spot energy. By spot, in Europe, we mean the intraday. So basically, really approximating the real time, but not yet the real time.
This is basically the simplified market design, which, for some aspects, maybe could resemble to the plain original California example, the one having so many issues. Why this? Let's go back to the process. When the first European directives liberalized, at the end of the next century, the power market, we had very often national monopolies. There was already no pool operational in a multi-regional market. But in all the other cases, we have national markets open up to competition.
And immediately, some power exchanges started operating to provide liquidity, trading, and pricing. After set of years, if I'm not wrong, it was 2006, the first pool market coupling project emerged, so-called trilateral market coupling. It was coupling France, Belgium, and Netherlands, so one big country with two small ones.
And the basic concept is the one we have today. So one algorithm shared among the parties, sharing, in an anonymized way, all the bids and offers in order to make them run together, just like in a single power exchange. And this algorithm was run separately by all the parties, checking one against the other. If the outcome were the same, then it became a rotational exercise.

And step wise, this started growing up. It was still a purely ATC-based model, so a zonal ATC model, so quite simplified. Then step wise, it included Germany, Luxembourg, then there was the Nordics, then Spain, then Italy. The more it was growing, the more it became incorporating further complexities.

The new countries had different local market designs. For example, in Italy, we have unit bidding, which is not the case in other countries. There are different kinds of products, which are all supported by the same algorithm, despite the fact that they are used only here or there. So quite a complexity for the algorithm. With expansion of the coupled area, flow-based became a need to better approximate the true reality of the grid, which was simplified. And then gradually, this became a success story. This was completely bottom-up. This was a commercial initiative by a set of parties.

And the reason for that was clear. It was one of the few cases of pareto improvement. It was consensus. Power exchanges got further trading volumes because they were trading the cross-border flows, which were substantial with respect to the local markets. TSOs get a better allocation of cross-border capacity.

ANTHONY PAPAVASILIOU: I don't know if it's the case for everyone, but I cannot hear Cosimo anymore.

COSIMO: And very often, that proved ineffective. So that was beneficial for TSOs. For market participants, that was providing more reliable pricing and more secure trading options. So that became clearly a success story, and everybody freely decided to jump on board because there were benefits for everybody.

That was so true that a certain moment, the new directives and regulations in Europe took this market coupling principle as the target model for Europe to deliver the internal European energy market. That was initially a commercial decision of a set of parties became a legal obligation.

Power exchanges became nominated electricity market operators. You had to apply for that to show having certain requirements, and then you were assigned the role. And there are rules about the way to design, operate, and maintain the algorithm and all the rest. So what was a commercial initiative bottom-up became a top-down regulated market design.

The last development, and this has been the launch a few years ago of the continuous trading, which is growing rapidly, now this intraday auctions and the completion of the EU market, which we reached a couple of years ago. So now Europe is a completely integrated market.

One could say the cost for that was this simplified market design, which makes it easier to integrate new parties. The benefit for that was the additional welfare for everybody. So my interpretation is that this kind of process has been somewhat an explicit decision to have, as a first target, the completion of the internal market because that was delivering higher welfare benefit, then a deeper optimization of the local markets as they were.

Indeed, some other country proof of that is that on the other side, on the TSO-driven markets, the local balance in real-time markets, everything is still pretty national with first attempts to create EU platforms where to exchange balancing resources. But market design is still very local, operation is completely local, and it is far from being reached until now, a sort of EU coupling of the real-time market.

This is what happened in the last year. We also saw that in the last year, the complexity of further extending geographically but also including new complex requirements in the algorithm is becoming higher and higher because we have so many parties, so many requirements, so many complexities. So any additional request becomes more and more challenging to be satisfied.

And now we have still, I would say, a few things which are relevant for the near future, and some of them have been already mentioned both by Pietro and Anthony. There is some market design debate whether nodal pricing would be fit for purpose for Europe and if Europe is ready for nodal pricing.

Optimization of energy and reserve is a further discussion, really, these days. Also, a complete change of the architecture of what we call the decentralized market cap in the way I mentioned. The European market today is one in Italy, another day is run in France, another day is run in Germany. This is in longer cycles than daily, but just to be simple.

And to move from this to the establishment of a legal single entity, a central place in Europe, doing everything for everybody. These are discussion on the market design, which would somewhat improve the efficiency of the system, fix some expected flaws for that.

Some counter-arguments for that, at least in terms of timeliness of such a decision, is that EU, by definition, apparently is complete. But practically speaking, or better, physically speaking, is not yet complete because we have three main holes to be completed. One is UK, which after the brexit, left the market.

And in the perspective that the transition is key because in Europe, we have the nuclear French, the French nuclear, the wide set of water reservoirs in the Nordics. We have wind in the Nordics, but also in Spain and Italy. PV is in the Mediterranean countries. So we have different areas where different kind of sources are procured.

Well, UK would be a major supplier of renewables, of wind. So a perfect integration through the market coupling of UK would be key. This is subject to a political discussion because UK is not anymore EU. So there is a need of a political agreement. But on the physical side and on the market side, that would be a game changer.

Second one is Switzerland. Switzerland is, as they say, it is at the heart of Europe, but outside Europe. And once more, wide part of trading opportunities, low flows, congestions throughout the triangle, France, Germany and Italy, stems from Switzerland. So incorporating, including Switzerland in our markets would be key.

And then there is currently, also the political process for the Eastern countries, which are requested, before being part of the EU, to be part of the internal EU market, which, once more, would deliver many benefits for everybody. And once more, here, the discussion is whether are higher, for a certain time of transition, the benefits of fine-tuning market design in the existing market or further extend the existing market, integrating new areas and securing trading opportunity, efficient cross-border trading, allocation of flows, and so on.

And we have quite a significant point, I would say, in this kind of discussion, when we had the crisis related to the Ukrainian war. So the sudden disappearing from Europe of the Russian gas, which is still prevailing in many countries. It was still key in Italy, in Germany, and driving prices and securing security of supply.

We had huge impact on prices, but ultimately, no real system security challenges for what dead market can do because the dead market, on a daily basis, continuously allocated and reallocated flows and counter-flows in completely different ways from one day to the other, with no need of explicit instructions from TSOs. That was simply the market outcome.

We had, from one day to the other, changes of the flow from the North to the South, and vice versa, on a structural basis, perfectly and smoothly managed by the market, which is the core also of the statement of the European directive-- the discussion on the change of the market design, saying currently, the spot market is fit for purpose because it supported a well-ordered management of the crisis in this moment. TSOs at the outcome of the market, a perfect scheduling of power plants and cross-border flows, thanks to the markets. So this is still highly valuable. So this is why until now, the EU market has been characterized by a sort of simplified market design. These are the benefits it's delivered. Now, the point is the way forward, if it is already the time to make it more sophisticated or if there are still benefits to be reaped through this kind of process by further enlarging the market in the next years to come. Thank you.

YONGHONG CHEN: Thank you very much, Cosimo. It's a really great discussion of the EU market that you are [INAUDIBLE] the challenges and opportunities. Thank you very much. So I'm Yonghong Chen from NREL Grid Planning and Analysis Center. So I'm leading this project on inter-regional transmission operational coordination.

I'm very thankful for the support from GDO on this important topic. And this morning, we have heard a great discussion and experience sharing from both the North American and the EU countries. So the reason we are looking at this problem is because right now, there's a great discussion about the transmission expansion, especially across these regional and inter-regional transmission expansion. And this morning, we heard there are some already existing coordinations across RTO regions and also between RTO and non-RTO. But in US, the coordination mostly happen in real time and with significant opportunities for improvement.

And there's a limited coordination in the operational forward process. Sorry. You they asked me to move further out. I don't know if I lost connection. Can you still hear me OK?

YAMIT LAVI: Yeah, we can hear you.

YONGHONG CHEN: Yeah. And then this inter-regional transmission coordination project right now is focused on the inter-regional congestion management, but we're also open to other areas of coordination. First, we'll look at the value and needs for the coordination in the forward process.

Just like our EU colleagues shared, the European started with the day-ahead and the intraday, but US hasn't done very much coordination in that time frame. And then for this real-time market to market congestion management or interchange optimization, there is still opportunities for improvement.

Then we're also look at inter-regional, the HVDC optimization, and the reserve deliverability. So this graph basically shows the two main functions in the operations. The one is in the balancing authority and the other one is on the congestion management.

So this interchange optimization presented by Feng this morning is more on the how balanced the balancing authority area. And then the market to market coordination implemented by MISO between MISO, PJM, these are more on the congestion management.

So right now, they are already existing methods in all these different areas. But definitely, it's not optimized globally. The question is how we can improve existing coordination process across the markets and then to enhance the reliability and economic efficiency.

And then the second one is how to coordinate across multi-region after we build the inter-regional transmission to achieve maximum benefit. So this morning, the ISO-- Matt also mentioned about this loop flows in the Northeastern region. But after we built this HVDC network, it could potentially be similar problem on large scale.

And then I have a few slides to summarize, basically, the coordination rate across all these different systemwide constraints. So we mentioned about balancing authority for port balance, then the

transmission constraint, currently mostly looking at the energy flow, but there's also a reserve requirement if we have a single market that you basically jointly procure reserve.
And then there's another one is on the reserve deliverability, really, is energy plus reserve flow. Anthony mentioned about the challenges, the research they have done in Europe. And all these full set of constraints today, actually, they are co-optimized in the ISO RTOs, especially the first three.
The last one in recent years, MISO and California ISO, also introduce this constraint to ensure reserves are procured at the right location. And it actually will introduce the zonal and nodal reserve prices.
But on the other extreme is like if there is no coordination, especially today, across multiple RTOs or between RTO and non-RTO regions, there is very limited coordination. And then essentially, the net schedule interchange or loop flow, these are driven outside of the market. And then it could introduce the inefficiency and unreliable operations.
And then so that's why there's some methodology developed. So today, we're somewhere in between. So there are some coordinated transaction scheduling or market to market congestion management and reserve sharing. So if you think about this full set of constraints and then there's a possible combinations, right?
So essentially, we can outline there's possible maybe 12 different combinations. Some of these already happened during the transition of the market. The C1 is basically the interchange optimization problem. The C2 is the market to market congestion management. C3 is MISO study market in 2005 to 2009. And then all the way to the very end, you could have the full multi area coupling, like what they implemented in EU. But-- sorry. But it may have to go with a simplified model because if you consider all of them on a nodal granularity, the problem can become very big and difficult to solve.
And then, so this is kind of a summary all the way from no coordination to fully coordination. So in our project, we're looking at a few key issues. The first is the impact from different coordination at different operational stages. So like [INAUDIBLE] mentioned, they started with day-ahead and intraday, but in US, the coordination is mostly in real time. So which way will give us the most value?
So research area one is basically develop the benchmark optimal mathematical model for each configuration. And then develop this multi-stage simulation with the flexibility to study different configurations. Then we'll have a consistent way to measure economic and reliability impact.
The second issue is, really, the strategies to address the computational complexity and the challenges to create new business structure. So basically, it will take a lot of both the technical and the business, the challenging, to build something like this large-scale coupling.
But in between, there should be some approximation or maybe some distributed coordination, just like the coordinated transaction or M2M congestion management. It's more like each RTO will clear their own problem, but exchanging information to achieve a distributed coordination.
So I showed some kind of example of different research topic like here, the benchmark model for the M2M JOA. So we can build this mathematical model to show what the best outcome this structure can give us.
Then in terms of the different coordination model, like Europeans coupled zonal clearing, that it can allow large participation, over 900 gigawatts. But in the US, it's more within each RTO, you have much more granular nodal clearing, and then each RTO is up to 180 gigawatt.

There's a basically tradeoff between these different models. And also, across the multi-stage, you could have different implementation. Like European has a coupling day-ahead but not very much in real time. And US is opposite.

So essentially, we're trying to build a framework saying, if we have this different structure, and it give us the commitment and the dispatch plan. And we need to also build like an emulation of the actual system to show, consistently compare these different configuration and the solution method.

So here is some quick example on 96Bus RTO system to run like a different configuration, for example, day-ahead, no coordination, versus, fully coordinated market to market congestion management. And then real time also has these two different configuration. Then it will show day-ahead-- in this small example, this shows, if we coordinate in the day-ahead, it actually will give us a lot more benefit.

And then when you get into real time, coordination can be actually better than no coordination. But overall, the day-ahead can actually give us more improvement.

Then there's a solution method. We can do a large coupling, just like EU on large scale. But you may have to go with a simplified model to overcome computational challenges. But another way is you can solve two regions that exchange information trying to achieve convergence.

But in day-ahead, it can also be difficult to converge across multiple area. And then when you get into real time, it's mostly on a rolling basis and trying to achieve convergence after multiple intervals.

So in summary, our work will build the study framework in the Sienna open source tool at NREL for multi-region, multi-stage, and multi-configuration coordination method and also develop this real-time emulation to consistently measure economic and reliability impact. And then we also will use that to analyze complexity, efficiency, and reliability.

The project right now, we focus on the congestion management. So tomorrow, we'll dive deeper into our project scope and the research funding in the past eight months. We still have another six months to go. And then we will also have my colleagues, Jose Daniel Lara and [INAUDIBLE], to share the software development and the case study-- the plan for the case study on national transmission planning models. So with that, I will stop and hear any questions.

TIM MEEHAN: It does not appear we have any questions in the chat or in the Q&A.

YONGHONG CHEN: OK.

TIM MEEHAN: Then I'll turn it back over to Yamit.

YAMIT LAVI: Yeah. Thanks, everyone, for attending today's workshop. And tomorrow, we start at the same time at 10:00 AM Eastern, 8:00 AM Mountain time. So, yeah, we'll go over-- like Yonghong said, we'll go over, in a little bit more detail, what the actual [INAUDIBLE] project is and some of the progress that we've made, and looking forward to hearing all of your feedback tomorrow during our open discussion time. So thanks again, and see everyone tomorrow.