# GDO Virtual IRTOC Workshop – Day 2

SPEAKER 1: We can just go ahead and get started. These folks are coming in. So hello everyone again and welcome to day two of the IRTOC workshop hosted by the GDO, Grid Deployment Office and the National Renewable Energy Lab. Again, my name is Yamit Lavi here at GDO. And we'll go over a few things before we get started today.

So none of the information presented herein is legally binding, and the context included in this presentation is intended for informational purposes only relating to the inter-regional transmission operational coordination project. And the purpose of today's meeting is to ask your input regarding IRTOC topics. And 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. And 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 at this meeting. And 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 website or used internally. If you do not wish to have your voice recorded, please do not speak during the call or disconnect now. If you do not wish to have your image recorded, please turn off your camera or participate only by phone. If you speak during the call or use a video connection, you are presumed to consent to recording and the use of your voice or image. Yes, if you have any technical questions, you can type them in the chat box and select send to Tim Meehan. And you can also send him an email at timothy.meehan@nrel.gov. And you can put his email in the chat for reference.

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

So for agenda for the day two of our workshop, we'll-- I'll give a quick recap of what we went over yesterday. And then we'll have a couple folks from NREL give an overview of the national transmission planning study, as well as the barriers and opportunities for inter-regional transmission paper that they just released a week or two ago at this point. And then we'll have Yonghong give a talk on post transmission, which is more information on the IRTOC project, as well as some discussions from a couple of folks on the IRTOC software development and case studies. And then at the end, we'll have an open discussion to solicit-- to hear your feedback on our methods, as well as our approach and preliminary results.

Yes. And yesterday we had just a quick kick off. We heard from a few experts on their North American experience sharing from MISO, ISO New England, as well as the operator in Ontario. We also had heard a-- some information from the European experience on multi-region market coupling-- if we heard from experts on that. And then we also heard our initial background on the inter-regional coordination project. So now I will hand it over to David Palchak to give an overview of the NTP study.

DAVID PALCHAK: Thank you, Yamit. How are things looking?

SPEAKER 1: Looks good.

SPEAKER 2: Looks good.

DAVID PALCHAK: OK. All right. OK. Thank you, [INAUDIBLE]. So I'm going to be talking about the national transmission planning study. So this is a study that's been going on for about two years. I'm presenting here preliminary results, but we do hope to have this study published in-- hopefully the summer-- the end of the summer, maybe early fall. So I'll be showing some of the preliminary results and talking about some of the motivation behind it.

So this was a partnership with the Pacific Northwest National lab and the Grid Deployment Office, who funded the study. So the objectives of the study were to simply better understand the role value and opportunities for transmission across the US. There's some specifics about that are important. One of them is that we're really focused on the inter-regional and national strategies. I think inter-regional being the important emphasis there trying to add to what the stakeholders are doing in the regions and offer some different solutions or additive solutions for those processes.

So we did engage a lot of stakeholders along this study. Hopefully, many of you were probably part of this, and we really appreciate your involvement and we certainly wanted to be additive to what's going on in industry. And as is often the case with lab studies, we also want to develop new methods and provide some innovative feedback for the industry about the best state of the art, as well as develop some innovative methods.

So the way we approached looking at transmission for the US was using several different models to understand low-cost reliable transmission systems of the future. We did this in really two different resolutions. I think a lot of these models will be familiar to many of you. So in the blue, we have our zonal resolution. And this is where we're really looking at across many scenarios out to 2050. And we do that at the zonal resolution partly for tractability, as well as we're putting a lot of different details into things that aren't spatial. We're using policies. We're using different demand scenarios and building out a lot of different future grid scenarios at a zonal resolution.

So this map shows the resolution of at least the transmission system. And so we use capacity expansion models. That's the base model that we use to build out our scenarios. We also do some additional economic analysis and some resource adequacy deep dives within our zonal world across many scenarios. We did almost 100 scenarios for the study. And then we move over into the nodal resolution. And this is where we do a lot of painstaking translations, as well as transmission planning to some extent, at least as much as we can to get into our production cost models.

And we do this for only a couple scenarios. This is quite difficult. And we get quite detailed. We use network models. And we build out production cost models, power flow models, as well as do additional stress analysis with these nodal scenarios. I'll show a couple maps of what we came up with. These are-- we call them transmission portfolios. Ultimately, we're looking for implementable solutions to validate what we find in our zonal world. Certainly, not anything-- plans of service or anything of that in our nodal world. But we're just trying to test our systems and make sure that these are implementable and address some of these engineering challenges that planners would face.

So we do that for a few scenarios, and I'll show some examples of that. Overall, we're trying to really get a lot of scenarios, understand the challenges in the future and come up with some several good solutions, hopefully. So as we build out our scenario framework, the most important part of that is our different transmission frameworks. So you'll see these for transmission frameworks referenced in the coming slides.

So I'll take a minute to explain them. So our limited is our reference scenario. So in this scenario, we're basically trying to limit the amount of transmission that can be built across US. So we don't allow any new inter-regional transmission. When I say inter-regional, I'm referring to the 1,000-plus ERCOT region. So 11 different regions in the US. We don't allow new lines across those inter-regional seams in the black lines there. We're also limiting the total amount of transmission to recent observable maximums. You'll easily see this in some of the results. We're looking at essentially the last decade, the last 15 years, looking at what was the maximum observed and limiting the total amount of transmission that can be built in our capacity expansion model in this scenario.

And in our accelerated transmission framework-- so there's three of them. The alternating [AUDIO CUT] AC. So in this one, we're two maps. So you can see between the limit and an AC, you can see that we removed all those inter-regional lines. So we're essentially allowing AC to be built within the interconnections. No new DC connections in this case, but we're allowing as much transmission as is cost effective. And our bottom two, our HVDC scenario. So two different flavors of that. So our point to point. So that's essentially using more traditional HVDC. And you'll see that referenced as LLC or at least that's the cost that we use for these lines. And you see these as potential options on this map here in these orange lines.

This is not what eventually gets built. This is just what the model can see as potential new options that weren't available within AC. And then in our bottom one or multi-terminal is more of a mesh ready grid. So adjacent zones can connect here as well as some additional zones and expansion is allowed across the country in our two HVDC scenario. So you're seeing this across the three seams between eastern and western ERCOT interconnections. And so sometimes we'll refer to those as just our HVDC scenarios. So those are the four transmission frameworks or paradigms.

To expand our scenario matrix, we're also bringing in different demand growth. So in the top-right corner, you see three different demand growth low, medium, high. And this essentially goes up with more electrification of the system. So you'll hear me mostly refer to the mid demand in this presentation. In our high scenario, this is a lot of electrification by 2050. And so this is high is about 3% growth, mid is about 2, and low is about 1% growth nationwide.

We also look at three different emissions targets. So the current policies is essentially what was in the books by last summer. So any of the state RPs, as well as Inflation Reduction ACT, anything that was law by last summer is in our current policy scenario. We also have two emissions target scenarios. So 90% CO2 reduction by 2035, as well as a 100% by 2035 target. So that's the White House target, but not a law. So these are just our different decarbonization scenarios, as well for the emission target.

So this is 36 total core scenarios. And this can be a little bit confusing. Ultimately, we're trying to get a sense of the future and understand the role of transmission across these many possible futures. So I'm not going to go into a lot of results on all of these, but this is how we set it up in a lot of our results pull a simple common findings from all of these.

So for the next few slides here, I'm just going to focus on the 90 by 2035. So on the top right, you can see what that means for emissions. So the black dots show historic emissions. You can see that's been going down since about 2005, 2006, mostly driven by the changeover from coal to gas. And if you follow the purple line, which is our emissions trajectory in our model, it's a little bit steeper than that. But by 2035, we get to 90% reduction from 2005 numbers and then 100% by 2045.

And I'm going to focus mostly on the mid demand, as I said-- and again, there's the demand chart. So we call this sometimes our central decarbonization scenario as well. So I might refer to it as that. So a couple results on this specific scenario.
So first of all, we see a lot of transmission built when we allow it to be built. So there's rapid and significant growth under our decarbonization scenario. So here you see the transmission capacity for our four transmission paradigms and our three that we allow to build the AC-- the point-to-point and [INAUDIBLE] we're seeing 2.4 to 3.5 times the 2020 capacity. And we're seeing more in our HVDC scenario than our AC.
The blue line here again, I said I'd point that out. So that's our limited scenario and that's basically following observed transmission additions from the last decade. So following that out and it's building as much as we allow it to build and it is using all of that capacity, most of that in local interconnection capacity. So we are capturing what it takes to connect a lot of different resources. So we see spur and reinforcement mostly used in that limited scenario, but all types of transmission are observed for all these scenarios. It's all important. We do capture the local interconnection costs, as well as some of the higher voltage inter-regional lines. And I'll show some maps of that.
So showing those examples actually just that I just showed on the map. So if we look at our three accelerated transmission frameworks, we see transmission built essentially all around the country, but we do see some concentrations in the middle of the country as well as some other obvious trends. We see some southern trends as well as some north central trends that persist across all of the scenarios. So a lot of different common examples here that hopefully we've learned from. And I'll show an example of how we tried to distill that into some lessons. But a live transmission belt a lot in the middle of the country-- a lot of it to move wind and solar to load centers.
When we look specifically at the inter-regional transmission, we see it means different things for different regions. So this plot here [AUDIO CUT]
YONGHONG CHEN: Somehow we cannot hear, David. Can you--
DAVID PALCHAK: Excuse me, Yonghong.
YONGHONG CHEN: We lost you for a little bit.
DAVID PALCHAK: OK. Am I back?
YONGHONG CHEN: Yeah, you're back.
DAVID PALCHAK: Sorry about that. OK. So this plot, I'll just start over on the slide then. So this plot is showing the 11 different regions, the ERCOT regions. And it's showing the transfer capability over the peak demand. So as you can see in our limited scenario, where we don't allow any inter-regional transmission to be built, that goes down-- that's because demand is going up and we're not allowing inter-regional transmission to be built. If you look at the AC scenario, we're seeing in many of the regions, it's basically maintaining the current transfer capability over peak demand fraction. In some regions you are seeing WestConnect, SPP, and MISO-- as well as a few others-- you are seeing an increase in the total amount of inter-regional builds for those scenarios in reference to the peak demand.
As you go to the HVDC scenarios, you see some dramatic changes where a lot of interconnection is being built compared to the amount of demand in the region, especially WestConnect, SPP and MISO reaching over 1.5 for several regions. The other one of note here, ERCOT. So we aren't allowing connections across the seams and anything but the HVDC scenario. So you can see that it goes from a very small amount of inter-regional capacity to a relatively-- well, a lot more relative to what it was in our

AC-- in our limited scenarios. So a lot of transfer capability being built, especially for some of these regions compared to the amount of demand, an interesting metric there to look at.

If we Zoom in further at what's happening across the seams, essentially when we're allowing transmission capacity across the interconnection seams, we're seeing a huge amount built. So this is just looking at our HVDC where we allow the interconnections across all three seams. And you can see that we're increasing that by 35 to 50 times the current seam crossing capacity in these scenarios out to 2050. And you can see these lines highlighted here, the ones that actually have the colors.

So just to explain here the charts a little bit. So we break up our different HVDC technologies, as I said, into the LCC and the VSC, and you can see them highlighted here on the map. And so they're-- also the back to backs that are expanded in some cases in the point to point specifically. So a lot of seam crossing capacity built when we allow it and compare-- especially when you compare it to today's.

So why is there so much transmission belt? Well, basically it saves money. So approximately $1.60 to $1.80 is saved for every dollar spent on transmission. In our 90% scenario, that amounts to about $270 to $490 billion compared to our limited scenario, where we're not allowing transmission to be built. The other thing you can notice in this plot here, so we've highlighted our course scenario that was represented by the 90% mid demand scenario. This also shows all the sensitivities around those scenarios. And I'll show a list of those sensitivities here on the next slide.

But ultimately, what you're seeing is across many of the future scenarios that we're looking at, we are seeing savings when you're allowing transmission to be built. And so that's represented by these gray lines and the light-colored bars as well. It's a pretty consistent message that you get savings with transmission.

So in addition to our core scenario-- so that's represented by the transmission and the demand and the emissions targets in the top right. We also ran 15 sensitivities on our 90% case just to make sure we understood the different pieces of uncertainty and how that we can pull lessons from that. So you'll see references to cost a lot on this table. So we're not going to go through all of these, and I don't think that's necessary. But you'll see references to cost. We changed costs on a lot of different technologies. If you go to the bottom, you'll also see we changed availability of different technologies-- some maybe nascent technologies in the case of H2 and CCS or new nuclear.

So taking those technologies in and out to see what impact that has on the role of transmission in the future. And to just fly over what that looks like-- so the spatial distribution of transmission is robust across a lot of these sensitivities. So the core scenario in the top left is what I showed previously for the AC paradigm. And if you look across all of these maps, this is the sensitivities of that paradigm. And at a high level-- one of the good things is there's a lot of common solutions here that gives us some confidence that a lot of the solutions that we can come up with and distill from this would be common in many, many futures. So that's one of the reasons we look at these maps and run all of these sensitivities is to try and pull out the lessons across many of them, as well as some of the other additional lessons where you get down to the bottom row here, where we don't have some of the technologies, transmission has the potential to become even more important in those futures. But certainly a lot of variation in here as well.

So when we take all of those maps and trying to distill them into a single map that we can actually move forward with, what we get is this. We call this a high opportunity transmission. So this is showing the new inter-regional transfer capacity that was essentially robustly developed across our sensitivities. So we cut off this number with a-- had to be in 75% of the sensitivities I just showed. So if it was in 75% of them, it made it on this map as our high opportunity transmission interface. Just to give some perspective on how big the transmission still is, even with that, somewhat conservative estimate-- if you look over at the PJM East central corridor, that is about 28gw now in 2024. They're looking at an expansion out to 2035, in this case, by another 12gw. So a pretty large expansion.

And then if you look out west in the Northern grid, South and WestConnect North connection, it's about 2.5gw now and you're looking at additional expansion of 6 gigawatts across our sensitivities. Still big expansions and a lot of opportunity here. That is robust in a lot of features.

So I'll quickly go through a couple examples of our nodal scenarios. So we ran three different scenarios. Notably, it's quite intractable to have all 100 scenarios modeled, but this is really just to do some detailed transmission planning and look at the engineering challenges of implementing these solutions. Certainly not a plan that we expect or is not a plan for the US, but really to try to validate and test our solutions and also look at analysis of grid operations, the scheduling challenges and the balancing challenges as well. Get some insights about how these futures could look.

So these are two nodal implementations of the AC and the MT-HVDC. So that's a our HVDC scenario, in this case, encompasses characteristics of both of our HVDC scenarios. And ultimately, you see a lot of transmission-- new transmission built. That's the highlighted lines here. A lot of 500 kV in our AC case, as well as some additional voltages, largely maintaining voltages within regions in some cases. And then our MT getting into a very transformative scenario, in this case, a lot of connections across the scenes, across the east, west and into ERCOT from both interconnections. So very interesting implementations here, ultimately trying to examine some of the engineering challenges and operations and validate that the systems that we're looking at that are sometimes transformative are implementable when you start to get down into more detailed modeling. But again, they're just in the modeling phases here.

And to just take a look at the different operations for this. So this is something that we created just to get a bigger picture of the nation here because it is difficult to plan across the whole US. And as you watch this, you can see the sun coming up and the solar coming up. This is two-days snapshot in March. And you can see the changes on the transmission that's happening. And we use this to try and quickly assess what's going on around the country as we build out these very transformative scenarios and understand where is transmission needed when we're building sensor transformative scenarios. So a tool for us and also a pretty picture of what's going on around the country and how the transmission system is changing.

So just to summarize here-- so there's rapid and significant transmission expansion and ultimately the HVDC scenarios build the most transmission. There are a lot of common transmission solutions as we saw. And then the detailed modeling helps to validate that these are implementable, at least to the extent that we can model them in those few scenarios. So I got to stop there.

SPEAKER 1: Thank you, David. I think we have one question from Phil McKay that we can probably answer right now. Just to clarify, this study does not include Canada or Mexico.

DAVID PALCHAK: We do. We have it in our models, but we are not looking at any detail at Canada or Mexico or making any changes to the systems. But we do have it in our network flow models.

SPEAKER 1: Yeah. Thank you. Think that was it. So I'm going to hand it over to Christina.

CHRISTINA E. SIMEONE: Hey. Hi, everybody. Can you see my screen here?

SPEAKER 1: Yes, yes.

CHRISTINA E. SIMEONE: OK. Great. So, hi. My name is Christina Simeone. And I'm going to talk about the report that was recently released on the barriers and opportunities to realize the system value of inter-regional transmission. And this is part of the NTP portfolio.

So basically, the motivation for this study is why might inter-regional benefits identified in planning models be different than the benefits observed in practice? And here we're talking about benefits like adjusted production, cost savings. We identify these issues and opportunities where they occur, for example, between non-market areas or market to non-market hybrid areas, trades between market areas or issues that are common to all areas. The report tends to focus on historical data and issues with existing inter-regional transmission, other than the transformative actions section.

And most of these issues and opportunities are identified by others. We also identify some of the potential system-- symptoms of inefficiencies like uneconomic flows from high to low price areas, high price differentials, underutilized capacity and lack of transparency. Although lack of transparency on inefficiencies is not really a system itself, it's more of a characteristic of bilateral trading areas where there have been historic concerns with rate pancaking, trade friction, limited real time scheduling options and use of more expensive resources. So just making that clarification.

So maybe less relevant to this group are the barriers and opportunities between non-market and hybrid areas to address the inefficiencies in bilateral trading regimes, balancing authority areas could implement coordinated scheduling or consolidate to an RTO-ISO to address inefficiencies related to imperfect congestion management methods like transmission loading relief in the east or qualified pass in the west for unscheduled flow mitigation. Balancing authority areas could implement joint operating agreements with neighbors to have similar congestion management programs or interconnection wide integration of paths and other methods.

Beyond order 890 and order 676(i), consistent methods and assumptions for available transfer capacity calculations between neighbors could be required to preserve reliability over market opportunities in emergency situations. There could be flexibility to adjust scheduling priorities to preserve reliability for Native loads. This is-- an example of this would be the wheel through priority for reliability imports in CAISO. Moving on to barriers and opportunities between market areas. We heard yesterday about the coordinated transaction scheduling systems that have been established in joint operating agreements between market areas. These programs tend to have real-time prices that are volatile and hard to forecast.

These could potentially be replaced with intertie optimizations. Transaction fees could be eliminated and forecasting methods improved, issues with market to market congestion management programs such as stale firm flow, entitlement assumptions or inaccurate constraint modeling could be updated and automated. Problems associated with the differences between the interface, where a transaction is scheduled and the interface where the transaction flows and is priced could be addressed with updated methods and transaction validation.

Currently, FERC requires merchant lines to make unused transmission capacity available to third parties and encourages this capacity to be made available to the market operator. But this doesn't often occur. CAISO's subscriber participating transmission owner model facilitates this by allowing CAISO to collect fees and remit to merchants for use of available transmission capacity.

Barriers and opportunities that are common to all areas-- deliverability uncertainty for external resource adequacy resources could potentially be addressed through a guidance framework. A large power transfers during extreme events can lead to atypical flows and potential reliability issues. Joint studies could occur to better understand and anticipate system to system issues and develop operational practices to mitigate these issues. In addition, there's opportunities to evaluate the internal system, to understand where these atypical constraints occur during large power transfers that impede required imports or exports, and then how to manage those atypical constraints.

And then lastly, some final thoughts. Improved coordination in the planning, scheduling and real-time operational horizons could lead to greater utilization and efficiencies. These are transformative actions that are listed on the screen. While the benefits of these transformative actions could potentially be significant-- and one only has to look at some of the studies documenting the EU single market integration benefits as an example-- These are technically and potentially-- technically and politically complicated issues that impact stakeholders in different ways, and this report did not explore those complicated dynamics.

So with that, thank everybody and turn it back over to Yamit.

SPEAKER 1: Thank you. If there's any other questions, we can take them now. Otherwise, we can move on to the next portion of the day, which Yonghong will give an overview of the IRTOC project which is currently focusing on congestion management.

YONGHONG CHEN: Yeah, can you hear me now?

SPEAKER 1: Yes.

YONGHONG CHEN: OK. Yes. So good morning and thank you for having-- attending this workshop and we hope to hear your feedback and advice. So this IRTOC project is sponsored by GDO. So we're very thankful for GDO to support this important topic.

This is a two-year project starting-- started last October, so we're about eight months out of the total 24 months of project timeline. Today, I'm going to-- me and the after me a few team members will dive more deeper into the our progress. And first of all, the background and the scope.

So like [INAUDIBLE] said, currently this project focused on the congestion management. Yesterday we had an overview. So for the inter-regional coordination problem, there are many different components. So if you have a different combination, you could have 12 different possible ways to really construct the coordination method. But here we focus on the congestion management.

So there are four key areas. first, there is in the real time market to market congestion management challenges. First of all, we focused on the coordination between market areas because the methodology is driven by the market clearing the optimization. And this method can also be extended to non-market area if there are also wrong security constraints-- the unit commitment or economic dispatch. But for other non-market areas today-- congestion is mostly handled by transmission loading relief. It's a quite different methodology. So our project will not get into that area. It's more still within this market framework.

And then so yesterday we heard all this discussion from North American grid operators. So these are M2M congestion management implemented between MISO-PJM and MISO-SPP. And actually, I worked at MISO for over 20 years before I joined the NREL last summer. So about 15 years ago, we implemented this real time market to market congestion management between a MISO-PJM And they certainly brought significant benefit for real time operations.

Later on it's also implemented between a MISO-SPP. But the-- in today's world, most of the time there's only one constraint activate in real time. And it's definitely-- this methodology if you have a lot of inter-regional transfer and the more binding constraint across the border, this methodology needs really to be investigated more to make sure there's a good convergence. Because even today we see there's a few constraints across the border, it can run into convergence challenging. And so sometimes they call the post swing. Basically, some oscillation can happen.

And then the second part is on the value and needs for coordination in the operational forward process is basically-- they had intraday frame. Yesterday we heard from our European colleagues and they want different way. It's not-- sounds like it's like it just organically happened. For this multi-country they figured out the benefit to-- for cross-border trading. So this EU model is like a very large scale but simplified zonal approach.

So there we mentioned all these future expansion possibilities across the country. If we build all these inter-regional AC lines or especially HVDC, how should we schedule them? So if you schedule is still happening within each grid operator or RTO and it's difficult to get an optimum solution for these inter-regional transfers.

And then the third part is really getting into the intra and inter-regional HVDC optimization. So there are some RTOs implemented, the intra-regional basically within this RTO region and HVDC optimization. It's mainly-- HVDC can relieve the congestion in the AC system. And then by optimizing the HVDC you can improve the reliability and the efficiency. But across the border-- so the there will be involved-- it will involve the part of the interchange of optimization. So it's much more complicated because there are two entities involved. And if this transmission is only optimized by one side, you end up with the similar issue. it may not be scheduled optimally.

Then the last one is on the reserved deliverability, both intra and inter-regional. So when I was at a MISO about maybe 12 years ago, there were some reserve transfer issue basically the reserve can create in a region in a sub area behind the congestion. And if you need that reserve, really it cannot be delivered. And then at the MISO we implemented this called post reserve deployment constraints, really trying to formulate the constraint with both energy and the reserve deployment flow and make sure the result can be pushed to the right location. But this one was not implemented for constraint across the border. So in reality, between two RTO, the deployment of reserve from both side can impact the flow in across these two regions. And then you need to make sure that this needs to be considered. And then when reserve deployed, the system is not over limit.

So basically, to summarize the three focus area-- the first is the M2M market to market congestion management on extra high voltage AC lines. This three sub area enhance the real time coordination method to improve flow and price convergence and then the coordination among more than two entities. So in the existing market to market construct, it's only implemented for two area. Yeah, basically if you have more interconnection-- the transmission line flow can be impacted by multiple areas. So there's certainly needs to look at beyond the two entity. And the third one is basically in the forward process-- like they had on intraday.

Now the second focus area is HVDC optimization like we just mentioned. And the especially, also in the forward process how we can schedule HVDC efficiently. But when getting into real time and may need to be adjusted based on the system condition change. And then finally, is the ancillary service deliverability, both the inter and the inter-regional.

So the next slide really is trying to say the single RTO co-optimization. It really brought significant benefit that we all understand. So on the right side, I showed some benefit analysis from MISO and PJM. So both indicated the market brought $4 or $5 billion a year benefit to the footprint. And we-- of course, it included both planning and the operational side.

So if you look at the energy entry service at MISO benefit is about $800 million a year and PJM is-- the energy production cost is $600 million. So they a huge improvement. So this benefit is compared with market and without market. So Christina mentioned the-- a lot of these issue. But if you consolidate these small country area into one large RTO, there's a significant efficiency gain. The RTOs really call optimize this system wide constraint power balance, transmission constraint, residual requirement. And finally, this is some relatively new development on the flow considering reserve deployment.

But now the question is across multiple RTOs reaching or between RTO and RTO. Today they are definitely-- Christina already mentioned that a lot of opportunity for improvement. But after we-- especially in the future build inter-regional transmission lines, how should we schedule and if we don't schedule them well, it could-- it will not be able to leverage or maximize all the benefit of building these lines. Yesterday we discussed the just the center around these full set of system wide constraint. You could have different configurations. Some of these actually happened as the industry transition to an auto market, for example, like C3 only consider energy like power balance and transmission constraint. That actually was the structure when MISO first started. Each of the local balancing authorities still manage their reserve. So MISO basically, clear the market and then send the net schedule interchange to each of these LBA, and then they will still run it on HVDC and the [INAUDIBLE] reserve like a power balance and-- I mean, for the HVDC balancing is already functioning and then--

But of course, the most optimal configuration would be the C11. Basically, a single entity can optimize everything together. The EIM model is simplified. You're using a zonal approach. And then there are some developments like energy imbalance market happening at California and they basically-- can CAISO and these other entities they jointly clear and basically optimize all these results and considering transmission constraints together.

So our project focuses on the congestion management. So it's really the C2 and C8. C2 is basically the current market to market-- the joint agreement between MISO-SPP and MISO-PJM. So really today is only considered the energy flow. So if you have a coordinated flow gate, the flow gate was identified for all these transmission constraints. It can be impacted-- have large impact from both sides, then it will be identified as coordinated flow gate. And then when these flow gates is violated or binding in real time, the monitoring RTO can activate that constraint and then basically request the other side to also provide relief.

That is two side exchanging shadow price. And then also, one side calculate a relief request trying to drive the convergence. And then-- but today, the reserve component is not considered. So there are times the deployment of reserve on one side can potentially cause congestion or overflow. But this was not considered in this joint agreement process.

So these slides-- yesterday I mentioned a little bit basically how these entities can coordinate together. So mathematically, you can formulate the problem and to solve the problem, you give the best possible answer. But in the implementation side, depending on the business structure, right? For example, if we have two RTOs, the European model is like we combine them together and solve a single large model. But on the US context, if you combine the two RTO and then trying to solve this nodal marketing model, there could be computational challenges.

So when I was at MISO, I worked many years on improving that they had the market clearing computational performance. So today these large RTO-- the market clearing problem is already pretty big and complicated. If we combine them to have a couple of clearing, you have to probably simplify the model. European basically went to the zonal approach, but we all know zonal approach has a lot of problems.

So basically in US all these RTO regions moved away from zonal to nodal. But the single large nodal modal it can give us a benchmark. So we can build that and then evaluate the computational performance challenging and then also the economical benefit gained by coupling them together. But even if we can address the technical issue on the computational side, it will require an entity to run this coupled market clearing. So that's also-- it's not going to happen quickly. That definitely will take time to get consensus on establishing something like that and then to perform these joint clearing.

So that's a problem with this approach. Another approach is basically-- we still have this regional market and then you can exchange information and trying to achieve convergence. That's basically, this coordinated transaction scheduling or interchange optimization or this joint market to market congestion management is all along that line. So basically say within my current RTO structure, I'll try to exchange some information on the shadow price or some of the relief information and hopefully we can exchange information to achieve convergence. But all these methods today is implemented in the real time, not really in the forward process like they had on intraday.

On the day ahead or intraday context, we normally just solve one problem-- one large problem at one time. So they have clearly just solve this problem then clear the market post the result. So if we want to do the coordination from that, then you basically need to solve the problem and then exchange the information across multiple RTO, then take that back and then do another iteration until it's converged. So this would-- first of all, there's challenging on the convergence because they had a whole process involved commitment. Problem is non-convex and now the convergence can be challenging. And then secondly, multiple iterations even on this sub problem probably is smaller than the combined coupling problem, but still take quite long. If you run multiple iterations the time can also be quite long.

So we feel like this methods is probably-- first of all, on the algorithm side, you need a significant effort to develop a method for convergence. And also, on the implementation side for these RTO to exchange all these information on these large market models, it's also can be very challenging. So within this project, we're not planning to study this solution method. So we'll focus on the left side-- potentially see what's the benefit of combining coupling and what simplification may help us to address some of the computational challenges. But we keep in mind that this approach will require maybe some entity to manage this joint clearing.

And then we're getting into real time. It's more like a rolling clearing. So normally, within one interval, it's pretty short interval-- five minutes-- rolling. And then normally, we don't try to achieve convergence within one interval. So today for both join to the coordinate transaction scheduling or M2M market-- congestion management, both side can solve the problem. And then after you solve it, you may still observe solution difference. Like, for example, for the same transmission constraint the two side may solve is different shadow price. And that's OK. We're just exchanging that information and move to the next interval and then take into account the solution difference on this joint constraints and then trying to drive convergence.

So basically, the convergence can happen after multiple intervals. In the meantime, system conditions may also change. So this process will take into account all these-- eventually, hopefully it will converge. But there's still challenges with today's process. First of all, we need to develop methodology or algorithm to drive better convergence. And also, if we have large number of M2M constraint-- the joint coordinated condition, the convergence can be even more challenging. So this hasn't been really looked a lot in the industry.

And then also about the coordination among multiple regions-- today it's just happening in two regions. So these are three areas we're going to study within this project. Here's the scope and the timeline. So we started last October. Now we're probably one third into the total project timeline.

There are three main components. First is the Sienna software development. Josiah is going to talk about it more later. So really, we're trying to develop this Sienna decomposition capability instead of solving an entire national wide large problem will reflect these regional clearing and the coordination. This will also be multi-stage-- real time is rolling coordination and with energy and reserve optimization. And then the second part is on the coordination structure. And the algorithm basically will build it. This methodology or solution algorithms for all these areas I just mentioned like HVDC optimization, resolve the deliverability, the M2M flow coordination, and then also develop this multi-stage simulation framework to be able to evaluate these different algorithm or methodology and coordination structure.

And the third area is on the case study. So we started with 5-bus and 96-bus system. We have done extensive prototype on only small systems. And then now we're in the process of moving to the NTP study model. So Jarrad we'll talk more about that. We're not planning to go straight to the national wide coordination. So we'll start maybe with a few areas such as MISO-SPP or MISO-PJM. Just look at this future NTP model with this new transmission buildout and how this regional operation can impact the scheduling of flow or efficiency on this transmission line transfer.

And eventually the final goal is to be able to run this multi-stage simulation with different coordination approach NTP size model. How much time-- So the first is the M2M congestion management on HVDC-- sorry, AC line and HVDC optimization. So these two problems we can look at them together. It's really just within this security concern the unit commitment economic dispatch, how we formulate these constraints. And then if it's across two RTO area, you basically have to break that into two problems and how to coordinate this common set of constraints across the border.

So in the real time coordination, this M2M across MISO-PJM, there's a benchmark model basically saying these two sides basically still have individual power balance constraints. The interchange schedule-- the net schedule interchange will still from the transaction is determine the outside of-- outside of the market. The each market clear their power balance equation and then-- but they will coordinate on the congestion management. So if there's a constraint across the border and it's binding or violated, then both sides can redispatch to resolve the constraint. You're trying to achieve the cheapest redispatch solution.

So this benchmark model basically have a joint transmission constraint formulation. Of course, in order to solve this model, you need some entity to have information from both sides. Then you will be able to build a model and solve this problem and get a single solution. So you end up with a single shadow price for this joint constraint. And that reflect the cheapest-- reduce measure option from both sides. But of course, in reality we don't have that. MISO doesn't know the information from PJM side and vice versa.

So the reality is you have to solve them in a distributed way. So there are two algorithms we developed. One it's called the distributed control through shadow price. So that was really an extension from existing methodology implemented between MISO-PJM and MISO-SPP. So we mentioned early this mastery in production. Sometimes you can run into convergence issues.

So within this project, we developed some improvements to hopefully have a more robust convergence. So we tested it on only small system and it demonstrated some better convergence with this improvement. And the second method is on this marginal equivalent. Basically yesterday, ISO New England also mentioned they develop this method for the interchange-- optimization problem. This is really both side exchange marginal unit and then incorporate that into their monthly clearing.

So we actually also adapt that for these congestion management problem. So you similarly will exchange marginal units between each other and then on one side will include them into the transmission constraint. But we'll still enforce basically saying the total redispatch [INAUDIBLE] of on the other side will be zero. Basically, we said no change to the net schedule interchange. And then we compare the-- these three different methods. The benchmark will give us a benchmark. And then the distributed control and marginal equivalent they-- both of the method will require multiple interval to converge to the optimal benchmark result.

So this is just a summary of where we are and the observation of this method. So this one distributed coordination through shadow price exchange-- this one is really purely based on the price. And then you have to guess how much relief the other side can provide. So that can sometimes try and cause some convergence. We tested this method on 5-bus 96-bus and also small 4 RTO model. And then this marginal equivalent to-- because you get the full marginal unit information from the other side-- so it will give some better convergence. And then-- but it's challenging in terms of determining the marginal unit, especially with energy reserve optimization. And also, if the reserve definition is different between two RTO that can be even more challenging.

So here's some preliminary result on a small system. The C2D is basically the distributed control. And then on top side, the C2B is the benchmark models. So you can see these C2D flow. It can be different from this. It will be the benchmark, but eventually it can converge-- similarly for the C2M.

And then the second row is on a price. So the benchmark model-- because we have a joint clearing, just a single constraint-- you have a shadow price for that constraint. But the-- only both of these, C2D or C2M, they have two RTO solving this at the same time. The price may not be the same immediately as the benchmark, but after some iteration, it can eventually also converge.

The bottom line is-- in terms of the generation dispatch. You can see the C2D-- sometimes it will take quite some interval for the blue lines-- basically the solution from this distributed method to converge to this orange line, which was from the benchmark model. But the marginal equivalent on the right side it can converge much better, but sometimes it can also take a few interval to converge to the optimal, especially when the system condition change, the marginal unit may change. So if you use the marginal using from previous interval, it may not converge immediately.

So the forward process is much more interesting. Yeah, we mentioned we were not planning to explore this distributed algorithm because in their head there's just too many constraints. And, for example, in MISO they had a-- it could have 200 some transmission constraint binding. And If you exchange the shadow price, trying to get convergence on all these constraints, it will take significant effort on the algorithm development side. And especially, there's also non-convexity involved.

So here we're trying to look at-- first of all, we build the benchmark model. And then the C2D-- and then the current practice is normally one RTO. The monitoring RTO will consider that the constraint the query, but it has to estimate the loop flow. From outside. It's normally pretty difficult. So it's a duty for these lines across border-- it's pretty difficult to get it correct in the forward process. And so we'll build some model-- but of course, you have to have some estimated loop flow for this approach.

And we also developed some simplified coupling approach. So basically, we can formulate the coupling problem. But then when we solve it, we can, for example, using LP relaxation. Of course, European method is to just simply go to the zonal approach. So I think within the nodal framework we can still explore some simplification. For example, this LP relaxation we don't solve the uni commitment. We basically just linearize to relax the binary variables. And another way is like maybe-- some of the inter-regional transmission-- works on the inter-regional. So these are the area we're planning to evaluate. So after we solve this first round, the simplified model, now we can figure out the HVDC schedule and the flow allocation across-- so for the inter-regional AC line, we can try to figure out the flow allocation for each RTO area. Then they can take these to run a more detailed clearing within each RTO.

So I'm not going to talk too much about it. The inter-regional optimization-- their formulation-- there's some RTOs already implemented that. But there's some interesting problems we identified with high renewable penetration on the negative price. So we have another project that will look more into that. And then on the inter-regional HVDC control, they also different ways you can look at it, whether this HVDC-- whether it will be part of the interchange. So that will determine if this HVDC flows just to relieve AC congestion or is it also trying to help more energy transfer across these two areas? And the-- depending on the purpose or construct, then the coordination or optimization methods can be different. But in general, we feel like if there is a large HVDC network, the best approach would be solve this coupled large area clearing and then to figure out the best schedule. It will be pretty challenging to just trying to coordinate and schedule these HVDC in a distributed way.

And now next is of course these multi-stage we talked a little bit like from day head to intraday to real time. You could have a different coordination or solution approach. And yesterday we mentioned a little bit-- after we tested all these different stages-- basically, they have to give you commitment. Real time gave you energy and resolve dispatch. How should we evaluate that?

So within Sienna we also-- in the process of building something called emulation, basically plugging this commitment dispatch solution and then ultimately test what the flow and the resolve deployment will be. What's the production cost for validation and then the combined cost?

So here's just one example with the RTS 96-bus system, including HVDC. At this stage, we duplicate the system to make them like a two RTO. And then it's probably different multi-stage combination. So here we said they had-- if we do the perfect M2M clearing and versus no coordination at all on this inter-regional line. And then the third one is the simplified coupling, like we mentioned earlier, to clear them together with the LP relaxation and figure out the flow allocation and HVDC schedule, then do the individual RTO clearing.

So there's-- I mean, of course, this is a very simple example and very preliminary result. There's some observations like no coordination in their head will result in higher real time production cost and higher real time flow violation. Just like in the middle line so you see all these bars are higher. So real time flow violation is a much higher. And of course, the production cost may be lower because you may not consider these constraints. But overall, if you add them together, it's a much higher production price violation cost.

And then the simplified-- the coordination-- it actually can achieve a similar outcome as the perfect. They had a joint clearing. So even if we do some simplified coupling, they have-- you can bring a lot of benefit. And in all these approach, real time coordination can bring benefit compared to no coordination in real time. But overall for these small example, day ahead coupling can give a much better outcome.

So lastly is on the ancillary service deliverability intra and inter-regional. The challenge is that resolve deployment can have many different scenarios. So energy poor balance, you just have single energy clearing. But when you clear resolve that-- how it's going to be deployed? There are many different possibilities like for continuous resolve. So you essentially you need to consider all the contingency events and after that how resolve is deployed. So there's a research area basically to identify the right transmission constraints and the relevant event to be formulated or added into the optimization.

And then this inter-regional transmission coordination. This is really getting into real time. Even in the EU real time, there's no coupling. So each RTO will solve the problem independently. But if you observe the flow-- inter-regional flow variation, how we're going to consider reserve deployment as part of it, right? [INAUDIBLE] should result on energy flow only. The different methods can drive the convergence. But if we consider reserve as part of it, it's actually much more complicated. We have some preliminary results. Sometimes difficult to converge into the global optimal solution.

And another piece of it is like in the multi-stage-- really, we should also look into the uncertainty, So the reason we have intraday is because the forecasting day may be-- with high uncertainty. And then, if you get better information into they need to optimize. And so we recognize that problem. But at this stage within this-- the scope of this project, we were not planning to try to develop a good data set for the uncertainty. We're just trying to do some reasonable approximation and then reflect that into the multi-stage framework.

And finally, it's just a summary. We're building the framework in Sienna, focusing on multi-region, multi-stage congestion management and real time emulation to consistently measure these different configurations and different solution methods. And also we incorporate intra or inter-regional HVDC and reserve their availability. And then this framework hopefully will help us to analyze the complexity, efficiency and reliability. Its benchmark model will give us some benchmark. What's the best outcome we can achieve?

And then really looking to simplify the single large coupling model and also, the distributed method-- the convergence by solving multiple regions iteratively. And we started-- end my presentation. And be happy to take any questions.

SPEAKER 1: Sounds like there are no questions. So we can move on to Jose's presentation. He's going to talk about the Sienna decomposition on the IRTOC software and development side.

JOSE DANIEL LARA: OK. Well, thanks, [INAUDIBLE]. As Yonghong mentioned in her presentation, we're working on developing the software architecture required to solve these models, especially at larger scale and with some realistic representation of some of the way that the operators work. So that's been done within the simulation framework called Sienna.

So for those of you who haven't heard of it, very briefly, Sienna it's a collection of open-source packages that we collect in several types of applications depending on what is required. So we have three big buckets of applications. One is Sienna data, which focuses a lot in creating data sets and joining power flow cases with PCM cases. We have Sienna Ops, which focuses a lot in applications we're going to be doing for this project and the type of applications that matter for representing the operations of our systems at different scales. And we have Sienna Dynamics, where we focus a lot on the dynamic performance of the systems, including, transit, instability and others.

One of the reasons that Sienna is being developed inside of the national lab is because for projects like the ones we are discussing today-- for these problems, there's an issue that is known as more limited choice. And it's when the situations where researchers or analysts can only formulate and can only perform research that is bounded by the capacities of the models they actually have at hand. There's two classes of model limited choice.

One is a structural, and is when certain classes of simulation and analysis actually do not exist in the tools that they have at hand. And the second one is when their formulation limitations, and is the cases where those analysis can be conducted, but they require doing it within the bounds of the existing models. I think that a classical example of a formulation limitation, more limited choice, is that some of the cases where production cost tools don't have the best storage models. So researchers have to adapt hydro models to be able to do that. And the same for projects like this where production cost modeling tools in commercial cases don't have the capacity to model these multi RTOs so you require including and making a lot of user-defined constraints. So you could actually-- you could try to simulate the type of behavior that you observe.

So Sienna is a far more open structure where we can have more flexibility into what we decide. And I just want to motivate one of the cases that we work in Sienna this way has to do, for example, in the case of Texas, where if you want to actually capture the effect of the price orders, you cannot do that with a classical two stage. You need to include UC. You need to include the [INAUDIBLE] or the day ahead and the real time. But you also need to include the auto market operations. And in many cases, and especially at the lab, when we want to evaluate merchants, we want to evaluate ancillary services as these simulations are requiring 6, 7 or 8 stages sometimes so that we can actually represent these behaviors that are outside of a single model.

So power simulation or JL is the base library where we're developing all of these capabilities. We basically focus on three main contributions. One is on the software engineering side. We're trying to define how should we engineer software for applications like this, using modern concepts in power systems-- sorry, in software engineering? We also focus a lot on the power systems modeling. How those-- how can we keep the representation of particular power system applications and make the problems still scalable? And of course, mathematical optimization, which allows us to say, how can we solve these problems more effectively?

And the way that we formulate an operations model in our system is distinct from classical power production cost models that have a single monolithic model that employs a lot of switches and parameters, such that you can arrive to different models. We actually think about composing those problems and composing those models by collecting a set of cost functions, collecting a set of device by device models that are distinct from each other and the branch level or the injection device. We couple them together in a particular presentation of the network, then we couple all of the services and then we use feed forwards as a way of sharing information between different models that have distinct formulations.

So what this allows us to do is that people ask us, what is the model of Sienna? Well, in Sienna, there is actually no model. There is no single model that you use. You compose it depending on what templates you create and you employ. So you can arrive to models that are more similar to myself or more similar to

CAISO or more similar to other European markets, depending on how you want to formulate each one of those devices and how do you encode the rules of these systems as part of the resulting model in Sienna.

So how do we use this? So like we go from this set of equations and this is actually how that looks like. We start from a network model, for example, a PTDF network representation that has its own assumptions. And then we define, as you can see on the right, how we want to model each one of the components individually and the reserves. So that's how we approach building models in Sienna, and that allows us to have a lot of flexibility about how do we want to simulate, for example, if there are different rules for dispatching storage into different RTOs, we can actually say, I want an RTO that has its own model of storage and the other one that has a different model. Or if I want to simplify an RTO, I can go into one RTO and say, I want to model this one just with some basic dispatch, or I want to model this one with a detail unit compliment.

So the other important concept of how we actually develop software tools for these applications is that we actually have these three lights-- this three type structure in how we think about the simulation. As I showed before, every one of the devices has its own model that creates an operational model. And every one of these operational models, again, because it's not monolithic, they're different from each other. So every one of these ones then gets all tied out together instead of a simulation model that combines them what we call a simulation sequence. And the simulation sequence is the one that defines how these different models share information.

One of the innovations that we have in Sienna is this type of modeling. Because at the end of the day, again, an operation model could be a bunch of merchant operators just submitting bids to the market. And then a separate operation model could be the market clearing and a separate operation model could be, for example, the supplementary ancillary market. So if you were trying to put all of this complexity into a single monolithic formulation that you modify through switches and parameters, it becomes really unwieldy. So we have here is that we have this disjointed approach and employ the simulation sequence as a way of coordinating.

So how do we formalize this a little bit more? Because it's not just the software, but how we formalize the sequence. So in Sienna, we have a distinction between decision models and simulation models. And Yonghong alluded to this a little bit inside of the-- in the previous presentation. So a decision model essentially is able to make-- operates over a horizon-- most of the time. Of course, you can always make a horizon of length one, which makes it like a narrow sided. But in general, we think about decision models have been having a horizon and they define an action variable u, which is a decision variable over a function that takes into account the state of the variable, which is x and the previous decisions or the previous state of the system. The previous decision was taken a set of parameters RHO and a forecast phi t. So like in this case, phi is the forecast available at time, t.

So we issue a decision-- every one of the decision models is a decision u and then the emulator actually evaluates what is the response of the system to that decision. So we solve this system of equations g, which could be-- is also most of the time formulated as another optimization problem, but made mostly out of equality constraints. And that emulation model takes the-- solves for the current state of the system takes into account the previous state of the system. The decision taken for that period and the realization of the forecast.

So in this method we actually separate the way that we simulate-- we think beyond modeling. So like when you think about even the words, it's like production cost modeling. We think beyond production cost modeling, and we move more into operations simulation. So we can simulate the operators making decisions with the information they have this phi t and making decisions with particular sets of assumptions and then having a model to evaluate what is the actual response of the system to that decision.

So it make it analogous to an everyday process. A decision model is similar to you taking your GPS-- and we're here in Colorado. So if we want to go and drive to Vail, you can take your-- decision model going to take you, this is the route you should be taking. And you should know-- this is you take a left turn and take this exit in the highway. And an emulation model is actually what happened with your driving that you're probably-- your GPS-- as you can see here, it says, it takes about two hours to drive to Vail. But what if you're driving and one hour into your drive, there's a car crash, your emulation model says, OK, how do I adapt now to the fact that I need to take a different route or the change-- that there's a change in the time that I expect to get there?

So the emulation model is to capture that. So because so much of the processes that Yonghong and the project describes are based on the state estimator and sharing information, this is where the emulation model becomes really critical because it's a central model that represents what happens in reality, subject to the imperfect decisions taken by different RTOs. So one of the things that we also do is that we have different strategies to make this scalable and large. One of the ambitions for this project is that we can run this in NTPs. So we formulate the problem in a way that most of the time we're updating the right-hand side of the optimization problem because we don't require rebuilding the matrix A or refactoring it. So in general, solvers are pretty good at you updating the resolving after updating B and then the incumbent solution actually speeds up the solution over the next step. So just to keep a small example here, we observe-- even for RTS type size cases, over 30% increase in speed between actually solving. So this is, for example, a model that has a unit commitment, economic dispatch and a power flow for the emulator. And the difference between rebuilding and not rebuilding changes even about 30% of the speed in a single laptop.

And so here you can see-- for about 10 days worth of simulation, you can see that, for example, we have this 2280 sol-- so the power flow at the emulator. So the way that we actually solve multi-stage simulations under this design is that we have-- we have the time series. We catch them in memory. We update the parameters of the models-- updating the right-hand side like I described. We update the initial conditions. We solve the decision model. We catch the solution into memory.

And then after all of the decisions have been taken in part of the sequence of decisions, we then go back and try to update what is the incumbent decision and solve the optimization problem that tells us what is the current state of the system with the emulator. And in this way, part of the software engineering effort is that we minimize the amount of interactions with the disk or with-- especially, in HPC systems or in cloud systems where these rights to disk could be in for several types of applications are done over the network. We can optimize those applications to the max so we know we don't write LP files. We don't throw CSPS. We actually have this specialized types of file systems that allows us to do this quite fast. And trying to have this balance between memory usage and speed of compute.

For a lot of the processes that we use in Sienna data, we take a lot-- this takes a significant amount of effort. And we have to develop the software to make these cases right as a large scale. We have to combine the network files. In the particular case of this project, we're using the [INAUDIBLE] case. The generation characteristics from nowadays, we have to get all the time series for the load, all of the hydro information and all of the renewable energy coming from. All of that is compiled using Sienna data into a fairly large system with over 200,000 lines, 190,000-- about 90,000 buses. And, i some applications, we're able to export to Plexos all the cases we just keep it in.

And again, I think that Jarrad is going to talk about in more details about NTP, which is the national transmission project. But this is the type of system that we want to solve these problems onto.

Now, one of the differences between models of this size and this complexity representing the real life operations of these large interconnected areas-- when we want to model market to market is the fact that we know, generally speaking, the [INAUDIBLE] literature thinks about it in these terms. We have two subsystems. There's an exchange. We want to coordinate that exchange. And these two subsystems are the two RTOs or the two ISOS or just the two markets that you want to operate.

So our objective is to think about how do we develop a simulation platform that actually captures more realistic topologies, a more realistic problems that are observed in these system? So like if we stay in this particular type of approach, again, there's plenty of academic literature who has looked into this-- has looked into ADMM, pre-composed it et cetera, et cetera. However, in real life and the data sets that we have built, every one of these subsystems actually is far more complex than just coordinating the unit commitment with the flows in between. Because every subsystem is composed of several balancing areas inside of the RTOs. And then these RTOs, these balancing areas sometimes will be connected between using AC interchanges that are normally for reliability reasons or for reserve reasons controlling the flow. But they will also have interfaces that usually are-- could be combinations of flows between multiple areas. Like for example, at the top could include HVDC lines, could include AC lines, because they're most of the time defined for, again, reliability or for n minus one limit flows.

And more critically to this project, each one of these RTOs can have sub synchronous-- sorry, asynchronous areas within themselves. So we have the RTO. The RTO has their balancing areas where there's some control in the flows inside of the RTO, as well as control between RTOs, which is this black line on the right hand of this slide is quite busy. But then within the whole system, there's also sub asynchronous regions separated by HVDC lines. So you need to be able to balance the RTOs, the synchronous regions and within the synchronous regions, the balancing areas.

So and this makes the-- makes a lot of complexity when you actually want to calculate in a computationally reasonable way. For example, what are the [INAUDIBLE] using PTDF? What are the actual flows? So if I actually want to calculate correctly the flow of that black line between the two RTOs, I need to be able to balance correctly all of the synchronous regions. And if I want to represent correctly the intra subsystem like in intra-RTO real life network constraints, then I have to consider all of these interfaces-- sorry, these interchanges between areas.

And what I want to make clear here is that a common confusion is to confuse what I'm defining in this slide as the interchanges between areas and the interfaces. Whereas an interchange is just a flow between two balancing areas inside of a particular subsystem, the interfaces are a subset of lines from which the total flow going through that is limited. And an interface is not limited only to the lines between areas. It could happen. So like, for example, at the bottom I put example where an interface and an interchange share the exact same group of AC lines. But in the top there is another interesting interface that includes one HVDC interface and also one AC interchange.

And I mean in this figure, to keep it reasonable, when I say AC interchange, it doesn't mean that that's a line. It could be made of multiple lines that connect the two areas. So we have these different levels of aggregation. We have AC interchanges that happen between areas that are made of multiple lines. We have interfaces where also made of multiple-- multiple lines and could imply flows between multiple areas. And we also have the interchanges that we want to cordinate. In this case-- only included AC. But think that Yonghong already alluded that the fact that we're going to include HVDC, but I didn't want to make the figure more complex.

So when we have to build something like that. And we also have to formulate how that looks like. And the solver needs to start tracking all of the details in the formulation, especially if we later want to apply some decomposition scheme. So the formulation has some sets. And we have the buses. We have the synchronous regions, the balancing areas, all the AC lines. For this particular project, we're stopping at two terminal HVDC. We're not including multi-terminal HVDC as HVDC technologies because first of all, I don't think there's any multi-terminal HVDC deployed. And the timeline, the schedule to deploy any of that are pretty far away.

Again then we have this inter area exchanges, which essentially are made of this combinatorial combination of different areas. We have the transmission interfaces. And for the sake of simplicity, I'll just create a single group of generators. But assume that those are like gas and hydro and nuclear and renewables and et cetera. We have the feasibility sets for those and the time steps.

Now when it starts getting complicated is when we have to start indexing and finding all of the different pieces that make up the models that make up this network formulation. Because we need to distinguish which subset of buses are in a particular synchronous region, which subset of buses are in a particular area? Because, as I mentioned before, in this scheme, we have buses-- we need to identify which buses are in the green circle, which buses are in the purple circle, which buses are in the red circle. So we have to index all of those.

We have to find which generators are in the green circle, in the red circle and the purple circle. We also need to identify which HVDC lines are assigned to each interface and which AC lines are assigned to each interface. We also start needing to identify which buses are the ones that are crossing-- which are the buses from and to of each HVDC line such that we can tell if a particular bus is in a different synchronous region and contributing to the changes through HVDC. And we have to do the same not only for synchronous regions, but we have to do it for areas. Is this HVDC-- an embedded HVDC but connected between two areas?

We also need to identify that for the AC lines, which lines are inside of a particular synchronous region. Now, the good thing about the AC lines is that they will never be in between synchronous regions because otherwise it wouldn't be a distinction between the synchronous regions. But we have to identify which lines are in between the different areas and which lines and which changes-- integrated changes are also in between the areas.

So this again, makes the problem really complicated because if you think about it from the software perspective, we have to have all of the mappings. We have to map all of these indexes to identify exactly what is connecting what and who is-- who belongs in each one of these circles. We also have different parameters. And in this particular case, because we have asynchronous networks, we also have to calculate a PTDF matrix for every one-- sensitivity matrix for every one of the synchronous-- the synchronous regions.

So again, we can be back in this situation where, for example, on subsynchronous region two, we have a single PTDF, but that PTDF is to coordinate the two RTOs because the exchange happens to be in that synchronous region, Then we need to get all the demands per bus. Then we have all the generators, maximum powers. Your maximum flow through your HVDC your maximum flows on the lines, your maximum flows in the interfaces, and your maximum flows in the interior exchange. This is the NSI-- I use a little bit of a different notation than your [INAUDIBLE], but this is the NSI, which again is a collection of branches.

So the model formulation-- one of the things that we're using the software is that we actually we utilize a lot of expressions. So in Sienna, we're able to keep track of expressions as objects so that we can reuse them. So we keep track of two types of expressions. One is the net injection at a bus. That is actually the demand minus the generation. And then we include the HVDC here. Because the HVDC allows us to calculate the injections that go into the PTDF flows. And then, the flow of every line is essentially the row of the PTDF times the injection of every bus.

And for models of the size of NTP, we have to apply a lot of techniques to get these PTDF rows sparsifying them, reducing the number of lines, collecting buses that are radio. And I'm going to go into many details of those. But essentially at the size of the system that we want to solve, this flow is the best estimate we can have given simplification that need to be done to-- make the model solvable even by commercial solver standards. So the model formulation at the end of the day when we collect all of the constraints and collect everything together, we looks like this.

So our generators-- here at the top level, we have the feasibility sets for different components. We have the generators. We have the lines. We have the HVDC, and we have the exchanges. All they have to be feasible, which in most cases for those flows is that they're within the bounds and the generators have to have-- depending on the model that you're using-- the minimal up and downs, their ramping, et cetera. So the first constraint is the synchronous region power balance. So all of the generation in the synchronous region plus and minus the HVDC input outputs have to meet the demand for that synchronous region. So that's the baseline constraint.

The second constraint that we see now is a power balance over the area. And as mentioned, one of the tricks that we're using in this formulation is that instead of adding all of the AC lines that connect the different areas, we use this idea of the changes that are just like a single flow variable that collects all of the flows of those lines. So if you have three lines connecting two areas, does the net change? The net change is this variable for the exchanges. So we have our generators in the area minus our flows in and out of HVDC for the area.

And then we have the changes through AC. And then the totally changes are the sum of all of the flows of the lines in and out and the sum of the flows of the HVDC. And I just spotted an error here in my model where the HVDC is twice. So this probably have something I have to fix in the slides. But essentially, what we do here is to say like we balance the synchronous region and we balance the areas, but we use these net changes for the-- we use this net changes that facilitate if we want to share information between the different models and we want to simplify. So we can have a group of lines, even though if we're not modeling all of the lines between the two areas being exchanged, we can still restrict the flows by restricting the net exchange. And

Finally, the last set of constraints are the sum of all of the AC lines and DC lines that make up the interfaces. So we have a maximum and minimum over the interfaces.

So again, if you look at this complexity of balancing all of these areas to this moment-- even though we've conducted significant research on what is the academic approach that exists-- this level of balancing is not being explored yet when you have to actually put it like that. So the implementation of the simulation, which is working progress, we're trying to implement all of the different methods that Yonghong explained where we do the benchmark model, then doing the coordinated through the flows and then the-- and then using the values of the system.

So what we're implementing is a workflow that looks like this in a new package called power simulation decomposition that will allow us to implement not only some of these methods, but some of decomposition methods to scale up future studies similar to NTP, where we can solve this benchmark problem. We can get from that benchmark. They had problems. The commitments, the responsibilities and ancillary services, the inter-regional flows. We can fix those. And every one of the simulation of the ED steps, we can read-- and this diagram is only showing two regions like if you might make it more regions, of course grows in complexity. But we read variables from the state and then solve the decomposed problem in R1 and R2, update the power outputs of those, solve for the emulator where we could even inject uncertainty.

So like we can solve the ED with a particular forecast, but then inject a different realization of the renewables-- such that this effect of using the previous time step from the state estimator-- we can include effects of having deviations from the state estimation versus reality in the emulator and we can solve these problems. So at each step of the economic dispatch, we evaluate all of the variables in a disjointed fashion to different problems that are solved independently. And then update the emulator to simulate the effect of the state estimation.

And then solving these problems at large scale requires several tricks for scalability-- like on the one hand, reduce rate of branches of the PTDF and specify the matrices so we can simplify the construction of the expressions for the flows. We can also-- we're also exploring the use of word equivalents such that even though in practice the two RTOs have visibility over the whole PTDF, you still calculating-- you still using a lot of information from the other RTO that makes it-- you still calculating a lot of flows in the other area. So the question is can we actually for the disjointed method, use word equivalence such that you can calculate your local flows and the flows in the neighborhood of the interchange you're trying to optimize, but you don't calculate flows further away from you that belong to the other RTP making the system faster? And then we also parallelize the build and solve of each decompose problem.

So thank you very much. Again, we keep working on this. This project is pretty exciting for us. From the software perspective, it's probably one of the more complex ones we're working on these days. And check out Sienna. And we're going to keep-- you want to keep updating the package to hopefully make the code production quality such that these simulations can be conducted given the interest in regional transmission coordination. These type of developments are pretty important because there are not that many tools out there that try to formalize this type of operational simulations. I don't know if there is any questions.

SPEAKER 1: Thanks for that. Well, we'll move on to Jarrad before we get into more discussions.

JOSE DANIEL LARA: OK. Sure.

SPEAKER 1: Thanks for the great presentation on the software. And now we'll introduce Jarrad Wright who will discuss the case studies for the IRTOC project and some more details.

JARRAD WRIGHT: [INAUDIBLE], I just want to confirm that you can see my screen with audio as well and you can hear me. OK, great. Yeah. So I'm going to try and talk through a little bit of a specific case study, but maybe just providing some context that would frame that more specifically for the purposes of this IRTOC project, and that is the national transmission planning study.

David had already presented maybe the 50,000-foot view of what NTP, what the objectives have been and also some ideas of the forthcoming publications that are coming from NTP. Similarly, Christina also spoke about some of the companion reports, or at least papers that are also coming from NTP.

What I'm going to specifically focus in on here is the context of NTP as a case study and building from what we did within the national transmission planning study to then take some of those large scale models and test these algorithms that we've been talking about for the last hour and a half or two hours or so at large scale. So really building on what we did in NTP-- providing the background on what we did in NTP-- specifically in this nodal space and then getting an idea or trying to give a feel for some of those key outcomes that we are starting to see as part of the NTP. And then finally, how are we going to build on that and use it for [INAUDIBLE].

So the first thing that I wanted to say is we want to start by-- and I just wanted to remind everyone in terms of these coordination configurations and the types of constraints that we would like to be imposing and controlling across the multiple RTOs. These 11 that Yonghong had already spoken about, two and eight being where our talk is intentionally going to be focusing in on. And then, of course, the example of where interchange optimization is C1 will be on C2 andC 8 in terms of the coordination configurations. And when you have all of those constraints included, which is obviously very difficult to do, especially at large scale, would be that C11 type of configuration where you have full multi-area coupling across multiple RTOs.

And this is only for information. And of course, this had already been described, but I thought it'd be important to just remind everyone of the level setting as to where we intentionally focusing our attention as part of this specific project. And again, as Yonghong had mentioned already, the project so far has gone from the left to the right-hand side, but not necessarily to the complete right-hand side. So 5-bus test systems, 96-bus RTS test systems, and then going towards this subset of the eastern interconnection, which would be in the order of thousands to potentially tens of thousands of buses, depending on the part of the EI that we'd like to focus in on and saying that we do want to focus in on a subset of these eastern interconnection, likely the region between MISO-PJM and MISO-SPP. And making sure that as we walk through these different levels and take the crawling, walking, then running type of approach, there may be some intermediary steps before we go to that large scale.

So I just wanted to note that here as well. Of course, the project is still in progress and we'll see how we go through the levels of complexity. We're seeing the computational challenges that we potentially see as we implement in software, specifically in Sienna that Jose had provided now that background and a consistent evaluation of the economic, as well as reliability impact. So how complex is it going to be attractable on these models, the efficiencies are looking at production cost as an example of in that emulation type of environment. And then, of course, reliability impacts the potential for shortages or relative flow violations between regions.

Now, more specifically on that subset of the EI, this just gives you a summary from NTP where we are leaving off the temporal resolution for the production cost modeling at a nodal level within the NTP project was a combination of the Eastern interconnect work as well as ERCOT, actually. But just for the purposes of today, I'm focusing in on the EI, where there's about 96,000 buses, 120,000 lines and transformers, 8,000 generators and storage components, as well as in about 41,000 individual loads distributed across the relevant nodes based on the power flow cases that establish that. The temporal resolution for the exercise that we undertook as part of the nodal PCM, and I'll show you where this fits in overall as part of NTP is hourly seven-- seven steps. So one week at a time, 52 weeks being solved in parallel near 24 hours with an overlap of 48 hours.

Now I'm mentioning stages there for the contiguous US type of run where we include each of the three interconnects. And those stages. I'll explain in the next slide-- a few slides in this next following section. But effectively what it is starting to increasingly represent or better represent transmission constraints. And for the purposes of NTP, the intentional focus was inter-regional. So we focused in on those interface bounds between regions. And specifically what we've defined as the FERC 1,000 planning regions, including ERCOT, but subsections of each of those in order to have some better spatial granularity. And I've given some information there around the interface bounds that were in the existing model. So that's the starting points, as well as then particular scenarios. I'll describe the three scenarios that we down translated into nodal models as well in the next few slides, as well as in the types of boundaries that we had as part of that to give you an idea of the type of complexity on the production cost modeling side and the interface flows that we see. And to give you a feel for the solve times as part of those stage one runs in the order of two to four hours for the stages 2 and stage 3 and 18 to 30 hours depending on the scenarios. So just keeping in mind here and that's why I'll put it in the bottom right. This is a global optimization of energy and reserves. And it has perfect foresight. So not necessarily a multi stage, but a single stage day ahead at an hourly resolution.

So to just give you a feel for these NTP nodal scenarios, this was the intention of NTP. And that's why I say this is where we building off and jumping off from is we take nodal starting points or industry planning cases. We have these capacity expansion scenarios that David was talking about a bit earlier this morning, which are at that zonal level of resolution. We have an idea of the interfaces between each of these zones and how they are going to be expanding as a function of the various input assumptions. And those sensitivities that he was describing generation and transmission are then traded off as to getting towards those least cost outcomes on the basis of input assumptions.

What we do then is we take the specific scenario as well as those nodal starting points, those industry planning places and undertake a zonal to nodal translation where we have this future representation with a very different resource mix, as well as a representation of this interzonal transfer capacity between the various zones. And for the purposes of NTP, those zones-- there's 134 of them across the contiguous US. I'm just showing a few here, just to give you an illustration of those outcomes where we build a very different resource mix as a result of the capacity expansion scenario.

We then have distinct individual expansions, new inter-regional branches that are shown in the dotted lines there, as well as new intra-regional types of branches that are defined by the scenario to then get towards the outcome that's representing as much as possible going towards the capacity expansion scenario in terms of curtailment, production costs, the resource mix. And in terms of installed capacity, of course, the energy dispatch is quite different between them as you're starting to represent more temporal constraints in the production cost environment than you were in that capacity expansion environment. But the real purpose of the zonal to nodal translation is really to get towards the transmission expansion needs. We get a better appreciation of the transmission expansion needs at nodal level of detail. And I'll try and just briefly talk through the three scenarios here. The next slide is actually more important. This is a quick summary maps at the top across the three limited AC and multi-terminal HVDC scenarios from NTP. And this is from 2035 for a 90% reduction by 2035 of CO2 emissions in the power sector.

There's a summary at the bottom as well across each of the main 1,000 transmission planning regions aggregated up as well on the left-hand side of each of those graphics to give you a feel for the total installed capacity by 2035, as well as then those maps give you an idea of, OK, well, where is it going to be? Where's a lot of the new resources going to be in terms of the outcomes? You'll see here more solar, lots of wind, as well as in where are generators likely to be deactivated or decommissioned as part of some of these futures? Let me see.

These are the three scenarios. This is just the desegregation of the generation capacity component of that of which in this next slide is where I'll talk to-- well, how do we actually now expand the transmission? And this was those stage one, stage two and stage three that I was describing a few slides ago, where we have this initial performance assessment where we unconstrained the nodal production cost model. We also then actually run a semi-constrained or a semi-bounded type of transmission constrained nodal PCM, where we don't necessarily bound individual branches but we bound interfaces and those interfaces are between these FERC 1,000 transmission planning regions.

So what we start to get a feel for there is where does the power really want to flow as a function of the new resources that are being added as well as generators and storage that have been added or removed as part of these futures? So we get that initial understanding and we then translate that into a set of snapshots. And that's what I mentioned at the bottom of this slide here. But those set of snapshots are then run in a linear power flow or DC power flow. We take the information from that and expand the transmission in that inner loop between the green or teal, as well as the blue color that transmission expansion exercise. And the tools that we use as part of that I won't necessarily go into today.

That iterative process is a combination of using typical classical, the industry power planning tools like PSC, as well as then some spatial tools-- so GIS tools to enable us to see where power is flowing. That visualization tool that David showed earlier also assist us in understanding where the power is wanting to flow. We do the transmission expansion to try and alleviate overloads. Once you've gone through the stage two expansion, we pass that additional transmission expansion back into that outer loop, into the orange transmission constrained nodal PCM and run this again starting to increasingly better represent or refine the treatment of nodal transmission.

And this is under normal conditions or n -0 in classical transmission expansion planning parlance. We then go towards a stage three where we also undertake a similar iterative transmission expansion exercise, but for single selected contingencies. And those single contingencies for NTP were those that were along the major interfaces between each of these FERC 1,000 planning regions-- transmission planning regions, as well as then primary buses back from that. So single buses back from that into the individual transmission planning regions. Similar exercise, linear power flow, and then sending that information back into a constrained transmission constrained model PCM where further strengthening may be necessary as part of that stage.

And of course, you can start to see that stage one, stage two, stage three, you can also foresee a potential future stage four, where you do AC power flow potential, stage five where we start to look at dynamics and start to think about the additional mitigation measures, equipment transmission potentially that may be able to be installed to then get towards some feasible futures. And those feasible futures I'm going to run through in the next two slides, but not necessarily for the intention of sharing the NTP nodal solutions and outcomes. A lot of that will be published during the back end of summer this year. But primarily for the intention of just sharing an understanding of the types of futures that we're seeing in terms of inter-regional transmission expansion. And this will be used as what we intend to use parts of the EI. In this specific case, the AC transmission expansion in 2035, We intend to use part of this as part of the IRTOC project. So leveraging off what had already been done to then really get a deeper understanding of not necessarily this perfect foresight day ahead, hourly nodal production costs, but also going into more detail around the various coordination configurations that we've been speaking about. So just to give you a brief overview of these futures and these expansions, we did intentionally focus on inter-regional transmission-- as I was mentioning-- but at the same time, any enabling intra regional transmission is also expanded. So getting localized pockets of new resources out and towards load centers, moving power across regions that are not necessarily adjacent to each other. So they need to move a lot of power, for example, from SPP across MISO towards PJM and potentially also from Florida to the southeast and the inverse from SPP-MISO down into the southeast FRCC, for example, when looking at the EI.

What we see particularly in the scenario is a lot of 500 kV being extended across into SPP where of course, the 345 kV networks are predominant at the moment and you'll see that across some of the major interfaces, SPP north, MISO north, SPP south, as well as MISO central. And then from SPP South down and across through that MISO south region and into the southeast where a lot of 500 kV is expanded, but on the basis of the existing 500 kV network that's already there. And we also have some selected inter-regional 345 kV expansions. And then, of course you'll see some of the existing 765 kV expanded from single circuits to double circuits. And of course, just keeping in mind this is a single realization of a single particular scenario in a single year to give a feel for the types of feasible transmission solutions that we could see for this particular scenario, for this AC transmission expansion scenario that David was previously describing.

And then I'll just go through the second one here, which then starts to bring in the HVDC component. So multiterminal HVDC expansion. The orange is the HVDC. The colors before-- the colors on the AC side are as before, so green being 345, red being 500 kV and then the purple 765. So you can see in this type of the scenario, number one, of course, as we were describing in the zonal results previously this morning, seems crossing capacity is expanded quite substantially between SPP as well as northern grid, SPP WestConnect, as well as in between ERCOT and WestConnect and then ERCOT and back into the EI [INAUDIBLE], as well as into the southern parts of MISO.

But what's also important here is the supporting high-voltage AC transmission that's needed to support these types of expansions. So it's not necessarily just the HVDC that's expanded as part of these. We want to see the type of HVDC as well, whether that's intra regional to collect and send bulk amounts of power across longer distances or whether that's to support for contingency performance when you have large outages on HVDC parts of the network that you can still transfer power into regionally across the major regions where you see the dominance of the HVDC networks. Very similar to-- as you can expect, because we use the capacity expansion zonal outcomes that you're seeing here. But this is now the specific nodal realization of that. And the starting point of number one, multiterminal HVDC networks already by 2035, as well as in some cases, for example, in WestConnect, parts of SPP really the potential for meshed HVDC.

And operations within those, of, course I'll start to talk about next. But just important to remember that of course, that would be quite novel in terms of operational challenges and opportunities.

This is a quick summary across each of these regions-- across each of the regions [INAUDIBLE] from NTP the types of net interchange over demand. So it's normalized to the demand and exports being on the positive side and imports being on the negative side. Of course, as you can note, several regions move in one predominant direction as exports, so SPP and MISO, WestConnect-- similarly, [INAUDIBLE] of course, is going to be looking like they're exporting a lot of power when you start to enable that HVDC links across into work-- parts of work as well as into the EI. Several regions also move power in both directions. So as imports and then some other regions as-- move power in both directions.

So regions that are predominantly importing CAISO, PJM, New York ISO and then others that move power bi-directionally. So the likes of NorthernGrid and the southeast across [INAUDIBLE] ISO New England, you can see that bi-directional flow throughout the course of the year.

Now, as I was mentioning, these are those idealized types of interfaces and the types of flows that you then see. And as part of ERCOT, the intention is now to start to think of different operational coordination mechanisms and start to test that at scale for some subset of the eastern interconnect. So the SPP MISO, MISO PJM types of interfaces and the types of flows that we would then actually see when moving from these decision models towards these emulation models and starting to actually emulate those and the coordination mechanisms that supported.

So to talk briefly, some of the key takeaways, there's really just three here for now. There are many more that will be forthcoming. But firstly, lots of opportunities as well as potential challenges. I was mentioning those for our ISOs and RTOs on this inter-regional coordination need. The high-voltage AC and HVDC that's embedded as part of that work together to improve contingency performance that expanded into regional transmission also means that we need to start to investigate it, which is what we're doing as part of this project, new potential operational frameworks to deal with these configurations. So multi-terminal meshed HVDC and how that links in with the supporting underlying embedded HVAC networks.

And then in the AC and multi-terminal HVDC scenarios, we do see more variation-- summarize that in the previous slide. We have a lot more information forthcoming. But I think for the purposes of this project, some regions become big importers and exporters that's why we're focusing in on this particular subset. Some are quite balanced, so it's not necessarily that they import or export large amounts, but they're quite balanced and some do import and export during the different periods. So we want to analyze those interesting regions.

We do see larger swings diurnally-- so this will be interesting to analyze further as well, driven by lots of solar PV and storage in particular regions. And we do see larger absolute power exchanges of course, and that's intentional and part of the design of the scenarios that were then down translated. So relative to that limited intra-regional type of expansion, we see long distance, large power transfers that are needed, increased number of inter-regional tie lines and then, of course, the potential for new voltage overlays. So moving from 345 kV to 500 kV potentially 765, as well as then as part of the HVDC scenario, the deployment of HVDC and multi-terminal and potentially mesh types of configurations.

So we think that the NTP inter-regional scenarios could be useful starting points for further assessments of these multi-stage and multi-region operational problems. And that's really what I just wanted to talk through in this last slide. Just in a few bullet points where we're going to intentionally focus on that subset of the EI. We don't necessarily have a particular decision on which parts and which subset of that. For now, we're thinking SPP-MISO or MISO-PJM or the combination of those. But if you remember towards the first few slides of this presentation, that scale starts to go towards thousands, tens of thousands of nodes. And of course, the problem in terms of computation and binding constraints becomes something that we want to be thinking about quite carefully.

But the benchmark that we expect in terms of this large-scale implementation is to choose the appropriate NTP scenario and have this global optimization of the energy and reserves. Perfect airhead foresight is what we have at the moment. So you could think of it as almost a C7 type of configuration-- if you remember back to, I think, it was slide three and conus wide. And this will be the basis to then derive these subregional interchanges and reserve requirements for understanding those coordinations-- operational coordination scenarios that we're thinking about so C2 and C8 as those configurations.

And I just wanted to note these in a few bullet points here is that when implementing at this large scale, we do anticipate some computational challenges-- probably not some, but many. We do anticipate potential convergence challenges and some of the distributed algorithms. And I think Yonghong spoke to that generally already as part of the test systems that we've been testing on. So coordinating a large number of constraints-- we do see that we to have to test some of the different algorithms as part of the different operational configurations. And we want to think of really using a small number of constraints initially and then generate the insights using the framework and the models that are built and the benchmarks that are built to then be utilized for future potential production use and broader scale development.

That the intention of this project is to understand and get a feeling for the types of coordination configurations, the performance that we see starting to make some key decisions potentially, and recommendations as a result of that in terms of the complexity of the different options, stay ahead real time, a day ahead intraday and then real time, in terms of the multi-stage approach, as well as then the multi-region approaches and the algorithms that support that.

And just to highlight one last point, in terms of the imperfect foresight and these look ahead-- a day ahead versus intraday types of realizations, is this forecast. Uncertainty is not necessarily something that's a part of our focus, but we want to be using some reasonable estimates for that. So we researching those topics at the moment and thinking about the types of data sets and time series profiles that we're going to be using as part of that. But the intention is not to focus on that levels of uncertainty and the types of data and time series that could support that, but just to use reasonable estimates to get an understanding across the various configurations, as well as the multi stage operations, the types of performance we could see.

And I think that is all for me. So I will stop sharing. And I'm going to give it.

YONGHONG CHEN: So [INAUDIBLE], [INAUDIBLE] may have more conversation with all this effort. And then if we-- I think after we build these two, it'd be great if we can use that for some studies or some use case-- some of the issues that they have. I mean, these entities have encountered.

SPEAKER 1: Yes. Yeah, definitely excited to keep in touch and keep-- hopefully-- yeah, we want-- the ultimate goal is for these process improvements to reach industry. So if-- and it's been a long day-- a long two days so I think we'll probably cut it here unless anybody has anything burning to say and we'll post. Yeah, like I've mentioned, we'll post the recording in the slides in a couple of weeks. And if folks have additional questions along with the recording and posting, we can include an email address that you all can send questions to or comments.

AUDIENCE: Is there a particular contact person that GDO would like to have for this-- who do we reach out to--
SPEAKER 1: I'll be-- I can be-- you can send me an email if you want to send [INAUDIBLE] you and you can-- I'll put my email on the chat and you can also send Yonghong email as our [INAUDIBLE].
AUDIENCE: Thank you. And thank you for your efforts.
SPEAKER 1: Thank you. Yonghong you can put your email in the chat as well.
YONGHONG CHEN: Sure.
SPEAKER 1: If you want-- if you're interested. And yes, that's all we have for today. So yeah, thanks. Thanks everyone for the-- for all the great presentations and for the engagement over the last couple of days. And we appreciate, and we'll keep everybody apprised as we go forward.
YONGHONG CHEN: OK. Thank you very much.
CHRISTINA E. SIMEONE: Thank you.