Harvard Electricity Policy Group
Virtual Session

Green Policy, Predictions, and Practice: Implementation Challenges December 12, 2022

Rapporteur's Report

TOPIC: The goals for carbon emission reduction and the precipitating event of passage of the IRA lead to a focus on implementation. All elements of the electricity system and markets face new stress tests. Absent the unlikely unlimited expansion of the transmission grid, storage and demand participation, the power system will face continuing, and even growing, operational constraints. Rapid changes in system conditions will be increasingly the norm, with implied or real prices more volatile. These are early days, with system operators and market participants seeking better models and practices. From an engineering perspective, there are new tools, practices and operating procedures being applied or under development, from ramping to state of charge management. From a market design perspective, there are calls to reimagine all the elements of long-term resources adequacy and short-term operations, especially pricing under stressed conditions. To what extent are these efforts reinforcing? Or are they proceeding as disconnected discussions? What are the underlying assumptions of the different approaches? How can we meet the policy challenges of the new system while preserving the best of elements of existing design(s)?

MODERATOR: Good afternoon, everyone. Hope you can hear me, and so nice to see all the familiar faces, I must admit. But I miss the in person HEPG meetings, but the second-best way to see all of you is wonderful as well, and I have the honored to introduce and moderate today's panel, and very much looking forward to definitely sharing this discussion and a very important and timely discussion this afternoon. Just a way of kicking it off.

I do interact quite a bit with my sister states in New England, and ISO New England in trying to develop the future role or evolving role of the wholesale electricity market in a market that is really transitioning, and I will just very briefly talk a little bit about the states' roll, and as the introduction to today's conversation, which is maybe somewhat in the minority. But in my world, it sort of feels like a majority of the states. Massachusetts has a legal requirement to decarbonize reaching net zero economy wide by 2050, and 50% reduction economy wide by 2030, which is a significant, and sometimes some people say, difficult to achieve or impossible to achieve, whichever you believe, targets or legal mandates for our decarbonization efforts. Of course, as part of the work that's being conducted both in Massachusetts, but also as a national level with the Princeton study, which we'll talk much more about, decarbonization, for at least this part of the United States, means that it requires us to electrify a significant portion of our economy, specifically, transportation and building heating and cooling and then green up our electricity grid. That's essentially our dominant pathway, not the only pathway, but the dominant pathway of decarbonization. That requires us to think very hard, and working with our neighboring states in New England and ISO New England, to figure out how do we prepare our electricity system for that future which, as all of you on this call know, that while 2050 sounds very far away, it's not that far away when it comes to the physical system, as well as the markets that accompanies that system and really drive that system. So lots of questions about where would the future investments be needed? How did you make those investments, and how to emphasize the importance of the markets? And really the most important thing that we're going to dive into today is, what are the market design challenges, and how to specifically maintain reliability and resilience in the face of climate change, while changing the generation mix because we have to decarbonize our electricity system, at least parts of the country perhaps faster than other parts of the country. And many other markets, in addition to New England, face the same topic.

Today we will dive in, and we will discuss how the system is currently handling large amounts of wind and solar resources while making investments in storage and transmission. The role of the natural gas generation fleets is definitely something that New England and the Northeast is grappling with. But as you know, many of the events that have occurred over the last two years, many of the other markets are grappling with as well. How to set market signals to ensure that the combination of these resources? Not just renewables, but clean energy resources, plus our gas fleet, plus storage and transmission. How do we properly set market signals to ensure that the combination of these resources will continue to provide reliability and serve the increasing amount of electric services that will be needed in the very near future.

We have an esteemed panel to talk about the challenges that's facing us nationwide first, and then we'll talk about how each of the markets see their role, and how to transform the markets and the system, both from a market perspective and operational perspective. So, we'll have a very rich dialogue and a very timely dialogue.

FIRST SPEAKER: The ZERO Lab at Princeton University uses macroscale energy system modeling to try to understand the future of our energy system. And in particular, we've been focused over the last couple of years on assessing the impact of proposed and recently enacted federal policies on our energy systems, particularly the electric power sector. I'm going to give a brief overview right now of results blending a couple of different studies. The first, the Repeat Project, is effort over the last year and a half, and continuing through the next couple of years, to try to provide a sort of real time analysis of the impact of federal legislation as it is being proposed and debated, something like a Congressional Budget Office for climate and energy impacts.

We have also been working furiously over the last 117th Congress to keep up with everything that's been going on and now have a report out, a preliminary analysis out on the impacts of the Inflation Reduction Act. We'll be updating and refreshing that in January. So stay tuned for that. Just today Princeton released a new report using a detailed electricity system planning model of the PJM interconnection to take a dive into the nation's largest electricity market and try to understand more specifically the impacts of federal legislation on the trajectory for the PJM region and for our ability to cut greenhouse gas emissions at an affordable cost here across the region. Let me summarize the high-level findings from both of those, and then look forward to further discussion afterwards.

At the high level, and for states like Massachusetts and others who are committed to this goal of decarbonization already, the big earth-changing events of the last Congress and the passage of the Inflation Reduction Act and the bipartisan infrastructure law means that now, for the first time in our history, the full financial might of the federal government is aligned behind the clean energy transition. This hasn't been the case before. As we all know, we've had states stepping out and leading. We've had on again off again federal policies for particular technologies, like the wind and solar production and investment tax credits that are on for a few years, and then expire at inopportune moments, and then continue again. That all changes really with the passage of the Inflation Reduction Act in particular, which now provides a substantial package of investments over a long decade-plus time period, with the focus on making clean energy technologies cheap. I should say clean energy and other climate solutions like land-carbon sinks and forestry management, and other things as well, that are supported by the law. What the Inflation Reduction Act does, in contrast to carbon pricing, cap and trade, or carbon tax programs, which have long been advocated for their economic efficiency focused on making fossil energy or dirty energy more expensive and therefore clean energy relatively competitive, the Inflation Reduction Act takes the opposite focus to shift the economics by making clean energy cheaper through a broad package of tax credits, grants, rebates, and loans or loan guarantees, which really span the full portfolio of technologies, or very nearly the full portfolio of technologies and solutions that you would want to see in a net zero emissions energy system over time. That includes, of course, clean electricity, particularly a long-term extension and return to the full value of the production and investment tax credits for renewable energy, but after 2025 and on, also all carbon-free electricity technologies. That includes new nuclear power or other zero emissions facilities that may or may not have qualified for the credit in the past.

Now resources can elect to take either and can more easily monetize those credits, including direct payments for those that don't pay taxes, like nonprofits and government-owned utilities, or assets and transferability to other third parties with business tax liability for those that do pay taxes. So now, instead of having to have tax equity partners with complicated transactions, you can simply transfer the credits to any other third party that has tax liability, which will make it much easier for these credits to be monetized. They're in place for a long-time horizon now. So, instead of periodic extensions and expirations, the credits are in place until the US power sector reduces greenhouse gas emissions to 25% of current levels. The year after that they retain their full value, and then they step down over the following 2 years. And given the growth in electricity demand due to electrification, it's likely that that goal will not be reached until deep into the 2030s, which means that basically we have subsidies in place for all carbon-free electricity resources, commencing construction through probably the mid-2030s, and completed through the end of the next decade. So quite a long horizon now to plan on.

It's not just clean electricity, though. There's new tax credits for hydrogen and clean fuels, including a \$3 a kilogram subsidy production tax credit for very low emissions hydrogen. The support for carbon capture and storage is increased to \$85 per ton for capture that's captured and stored and \$60 for carbon that's captured and used in some industrial process. That's up from \$50, and is enough to make carbon capture an economically viable proposition across really a wide range of emitting sectors, unlike today where it really only works for very concentrated CO2 streams like ethanol facilities or natural gas separation units. On the demand side, there's also robust support for electric vehicles, both personal vehicle adoption and business adoption of clean vehicles, as well as tax credits for electric charger deployment, and a set of incentives for energy efficiency and electrification of buildings as well.

You can see really all of the key building blocks of a client system that states have been pursuing and others by the Inflation Reduction Act, to the tune of, you know, somewhere between 10 and 50% off. Basically, everything's on sale now. Whatever level of effort made sense for a utility in their business plan or a state and their corporate, you know, their political strategies before, now we have an opportunity to increase those levels of ambition, thanks to the federal government, Uncle Sam, picking up a big chunk of the tab now.

Beyond just making clean energy technologies cheap, there's also a variety of other important ends to the Inflation Reduction Act, including a set of programs that are designed to drive the deployment and early market adoption of the next generation of technologies we're going to need in the 2030s and 2040s to be mature and ready for wide scale deployment. That includes clean hydrogen, carbon capture, advanced nuclear, advanced geothermal, long duration energy storage, etc., etc. Technologies that we don't necessarily need to deploy at scale due to market demand in the near term, but if we don't deploy them over the next decade we won't be able to replicate the kinds of cost declines, financial maturity, technological improvements, and other forces that have driven down the cost of wind and solar so dramatically over the last decade. Same for lithium ion batteries and LEDs. And so we can repeat that kind of dynamic, with both demonstration and hubs funding from the infrastructure law for first end of a kind projects.

There's also new early market deployment subsidies for the full range of technologies we were just talking about, so that they can begin to be adopted and scale up over the next decade, and be ready for primetime in the 2030s and 40s. The bill also contains a robust set of industrial policies designed to support the development of American manufacturing, of solar, wind, battery, and electric vehicle components and assembly, as well as critical minerals processing. You can see that as an SOP to domestic jobs. You can see that as an important political economy dimension of sustaining this policy over time by delivering jobs, and economic benefits that are tangible in near term, or you can see that as an important way to relieve supply chain tensions that are currently constraining the markets. Whatever your perspective on this, this is a particularly important and significant intervention into the economy, and one that is, I think, a reversal of the morally laissez-faire approach that the US government has taken towards these matters over recent decades.

There's also a package of environmental justice provisions that provide about $60 billion, designed to try to reduce harmful pollution in environmentally overburdened communities and ensure more equitable access to the clean energy solutions the bill supports. There's a variety of ways that tries to do that, which we can dive into later in questions, if you'd like. And then, in addition, the legislation is very focused on ensuring that new clean energy investments are driven into communities that are today dependent on the fossil energy sectors for employment and local tax revenue, what the bill dubs energy communities, and provides bonus tax credits for investment of clean electricity and manufacturing into those communities, as well as a new $250 billion loan program at the Department of Energy's Loan Programs Office, which can be used to retool, retrofit, replace, repower, etc., existing fossil infrastructure across the economy.

Alright, but what does it all mean for CO2 emissions, which, of course, is the central objective of any kind of effective climate policy? The REPEAT Project has been modeling these policies in detail using a set of macro energy system models in partnership with Evolved Energy Research. What we found is that the Inflation Reduction Act is likely to reduce greenhouse gas emissions across the US economy on the order of one billion metric tons per year in 2030, getting us into the neighborhood of about a 42% below 2005 levels. Now, that's not enough on its own to reach the 50% reduction below our peak emissions around 2005, which is the goal that President Biden has set for the country and pledged as part of our nationally determined contribution at the UNFCCC process. But it does get us to within about a half a billion tons, a much more plausible shooting distance than where we were without passage of the law, which is a 1.5 billion-ton gap after just passage of the infrastructure law or the IAJA. This is a substantial reduction in emissions that is achieved just by this legislation. With additional action by states, by municipalities, by corporate and institutional leaders, and maybe with a little bit of good luck, we may be able to close the remainder of that gap by 2030.

In addition to driving down emissions, the Inflation Reduction Act is likely to drive a wholesale change in the direction of fossil energy consumption in the United States. Since we discovered oil and gas, we have been using more and more of it every year throughout U.S. history, with brief exceptions during economic recessions or global energy price crises. That is likely to change with passage of this law, where our modeling shows the first sustained decline in demand of both petroleum products and natural gas in US history. Our modeling shows about a 13% reduction in consumption of petroleum products like gasoline or diesel fuel through 2030, and nearly double that, a 25% reduction by 2035. And similarly, we see about a 17% reduction below 2021 levels in natural gas consumption by 2030. Petroleum product consumption is primarily driven down by electrification of transportation and natural gas consumption primarily by the growth of renewable electricity and the maintenance of our existing nuclear fleet, which helps drive out natural gas power generation. Even though it doesn't necessarily reduce total power, natural gas capacity will be burning a lot less gas in the power sector.

Now, of course, we're going to see electrification, which is going to reverse another important trend that we all need to be focused on, which is that since really 2005, we've had basically flat demand for electricity, nationally. And that is again likely to change, thanks to the incentives for electrification under the Inflation Reduction Act, which is going along with trends that are already underway and the growth of electric vehicles and investment by the automotive sector. We're likely to again start to see sustained growth in electricity demand over the next decade and beyond, on the order of 20 to 25% growth by 2030, and maybe on the order of 40% by 2035. So once again we're going to be in a period of a couple of percent per year sustained growth in national electricity demand, something that we really haven't seen since the 1970s through about 2000.

In addition, thanks to the passage of the Inflation Reduction Act, it's possible for states and regions, you know, local governments and actors around the country to contemplate even deeper emissions reductions. A new report out today from the ZERO Lab looks at the impacts of the Inflation Reduction Act on the PJM electricity system, which finds that even without any further action, the IRA results in both lower emissions and lower electricity supply costs in 2030 than we've seen in recent years, and certainly lower than without the law.

We get cheaper and cleaner energy, thanks to the Inflation Reduction Act. But we also don't have to stop. there. If states continue to drive deeper decarbonization across the region, we find that we could cut greenhouse gas emissions not just 36% by 2030 under IRA, but somewhere between 80 and 90% by 2035, while paying electricity costs equal to or lower than, or roughly comparable to what we've paid in recent years, so less than 2021, and roughly comparable to what we paid in 2019 for electricity across the region. Whatever level of ambition made economic or political sense before passage of IRA, with the federal government picking up the tab, we now can contemplate even deeper reductions while maintaining affordability of electricity across the region. And this is true, not just for PJM, but for electricity systems across the country.

Now, our major challenge is, how fast can we scale? The economics are really no longer the barrier with the cost declines we see for these technologies, with the federal incentives in place. The challenge now is going to be scaling up infrastructure, supply chains, the workforce we need to build all of this to mobilize capital at the pace required, and to take advantage of the economic and public health and climate opportunity that we're presented with, thanks to federal legislation.

The REPEAT Project modelled the pace of transmission expansion that will be required nationally to unlock the full economic potential of the bill, which we estimate at about 2.3% per year expansion in the transfer capacity or gigawatt miles of transmission across the country. That's about double the pace that we've seen over the last decade, where transmission has only grown at about 1% per year nationally. Although it is only slightly faster than the longer-term average that we've seen from 1978 to 2020. In other words, we need to get back on the pace that we were on from the 1970s to the 1990s and accelerate to roughly double the pace that we've seen over the last decade. If we fail to do so, the growth of clean electricity will be constrained and unable to both keep up with the amount of demand from electric vehicles and other electrification, and drive out fossil generation from our existing portfolio. As a result, if we fail to grow transmission faster than the historical pace over the last decade of 1% per year, then we lose about 80% of the emissions reductions under the model unconstrained scenario, with emissions falling only about 200 million tons in 2030 relative to no Inflation Reduction Act. And if we can grow at 1.5% per year, then we still lose about a fifth of the emissions reduction. Transmission is one of several potential bottlenecks that, if we cannot scale up fast enough, we will not be able to realize the full economic and climate emissions reduction potential of these federal incentives. The challenge is, how fast can we scale up these critical infrastructure supply chains to deploy these technologies, the workforce to build it, and other non-economic barriers, which I think are going to become the central challenge for public policy and implementation going forward. You can find more at RepeatProject.Org, and I look forward to the further conversation.

SECOND SPEAKER: The Southwest Power Pool (SPP) is at the transition from the traditional system to where we are now and in between. We've been working really hard integrating in the renewables. I know folks are more familiar with PJM and ERCOT, and what's going on there, but SPP is sort of ground zero for wind integration in the system. SPP is about 53 gigawatts at peak loads, so a bit smaller than PJM, but larger than others, New England and New York and California is a little smaller. We're primarily a gas capacity system, believe it or not. We've got about 36% gas capacity, but wind does come in at number two at about 30%, and then coal is number three. In 2014, we only had about eight gigawatts of wind. We're now up to 32 gigawatts of wind capacity. So, there's been quite a substantial growth of wind over the last several years. And I will note that SPP is a more vertically integrated system than most of the other regions, and so we have not experienced a significant reduction in coal capacity or gas capacity. It has fluctuated a little bit. But we still have most of the coal resources and most of the gas resources. But we've added a lot of wind resources in between. So obviously that's having a significant impact on what we're generating. In terms of what we're doing and generating, we're now in a situation where SPP's primary generation fuel source is wind. Right? So 37% of all generations so far this year is from wind. Coal takes the second spot at about 35%.

SPP is a wind dominated system. I know that there's been a lot of studies, and I know some of the RTOs have looked at, jeez, what happens when we hit 30 or 40% renewable penetration? Well, SPP is already there. And so we are, in fact, experiencing some of the challenges that you might anticipate by having such a large penetration of wind on the system. I will note that when we look at wind, there's a few symptoms that we see with such high penetrations of wind. The first thing we're seeing is wind curtailment. And most of this curtailment is not operator-driven. So SPP is not actively curtailing much of the wind. It's actually market-driven. Wind tends to bid at negative prices, given the fact that there are incentives, let's say, and so they they're offering in, it could be let's say minus $30 or minus $35 into the market. We do see a lot of that curtailment being economic, which does have the effect of creating a lot of negative prices. But in terms of quantity, we're seeing a substantial amount of wind curtailed over the course of the year.

Wind curtailment is a big thing. I will note that the growth in wind has been pretty linear, but what's interesting is, the growth in curtailment has not been linear. A fairly limited amount of curtailment occurred just back in 2019, only of little over 100 megawatts on average for the year. So far this year, we're averaging over 1,200 megawatts in every hour, and there are times when we see entailment, and I was looking at the forecast for today and tomorrow, where we've got a forecast wind of around 28 gigawatts, which is actually higher than the forecast load in the early morning hours tomorrow. But I would anticipate, probably in the order of somewhere between six and eight gigawatts of wind is likely to be curtailed tomorrow morning. So, the magnitude of curtailment is rather large. You have a lot of this trapped, and what you're seeing is that that trappedness has really become really pronounced over the last couple of years in particular. So there's a lot of wind.

In my mind and estimation, we have really hit a saturation point where the transmission grid can't support significantly higher levels of wind. And as such we are seeing that economic curtailment occurring, primarily because of transmission congestion. So it's not kept up, and as a result it flows into negative pricing. What is the negative pricing frequency in SPP? And it's rather significant. Without anywhere to go, with negative offers, we see negative pricing. In April of this year, 30% of all intervals in SPP were negative. Now, one thing to note is, there's a difference between real time and day head, and we'll talk about that in a minute. But when you have such high penetration of wind, this is creating a significant issue with the congestion and we're seeing, lots of negative pricing.

We don't have much storage at this time. I think there's only in the tens of megawatts of storage in SPP systems compared to other regions. We're lagging behind on that. But if you look at price differences, it would seem that storage would be valuable. Alright.

We’ve also been looking at make-whole payments to try and identify what's been going on. We've been receiving higher levels of make whole payments, particularly in the real time. You'll see that that's sort of increasing exponentially. We do know that gas prices are going up, which is contributing to that. But when you look at the particular set of resources that's being affected, that primarily has to do with resources that are being committed to provide uncertainty reserves. The operators are committing resources because they're worried about wind volatility, and as such these resources are uneconomic. They're lowering prices. They're sitting at minimums, and as a result, there's a lot of make-whole payments that they're receiving as a result of those operator actions.

As for price convergence, there's a lot of difference between day ahead and real time. I know that just a minute ago [on the slides] we looked at it from an absolute perspective, and we look at it just as a straight average, and we see that the percent is increasing. Well, why is that so? That's because we have more capacity in real time than in the day ahead. Looking at all the sources of additional generation in real time compared to what goes away, what goes away is primarily virtual supply, and what comes in is primarily wind. We have more wind resources generating in real time than was anticipated in the day ahead market. Ultimately, this ends up creating that divergence that we're seeing in in prices between the two markets. There’s an inefficiency occurring between what the day ahead is doing and what the real time is doing.

Also, there are two primary routes that SPP has been focused on to try to deal with some of the flexibility issues that we're dealing with right now. One is ramping. 80% of all scarcity prices we see in SPP is a result of 5 to 10-minute ramping limitations. SPP software does not have look-ahead capability, unlike other RTOs, New York and California, for instance. Virtual bids are an hourly product. They don't solve a 5-minute ramping problem. And so, the solution that SPP came up with was the ramping product. It was designed to deal with hold back capacity to manage that. There's a demand curve to help set pricing. But the big issue we've seen over the last several months is that 50% of the resources that are being procured are resources on the wrong side of the constraint, effectively on the low side with wind being the primary resource there. If you're trying to meet ramp with wind that's behind a constraint, it's not going to provide much value. In fact, it does not. So that's a concern.

Then, we talk about uncertainty. As I said, RTO operators are particularly concerned about variability, and because we don't have a reserve that deals with variability. SPP has effectively created their own reserve without paying for it. What they do is, as I mentioned earlier, they commit lots of resources. It can be, let's say, 100 resources, totaling something like 4,000 megawatts, committed by the market operator to provide uncertainty in the event that there is wind variability, which does materialize time to time. As a result, what you end up doing is not paying for it. Now the design which has been approved by FERC, and looks to be implemented next year, is primarily designed to deal with that particular reserve that SPP operators are today getting and not getting in a way that's either co-optimized or priced. And so hopefully tomorrow that will be done.

And finally, the other concerns that we sort of note are related to availability, having resources available when needed, particularly when you have wind. You can have periods of wind where you're at 75-80%, for a period of hours or days, and then it kicks out, and then you're down to, 10-15% wind. You're going to need resources to be there and available, and that's challenging, particularly when you start thinking about outages. Obviously, transmission planning is a concern. I know MISO and SPP continue to talk about that and work on that. But unfortunately, I think we're again in a situation where it doesn't look like there'll be any transmission projects on the scene. As to resource accreditation is, how do you ensure that from the planning perspective, you're getting the resources and value them appropriately? And that does go for wind and other renewables. But it also goes to your thermal resources as well. So that's what I have for now. But I definitely look forward to your questions during the session later today.

MODERATOR: Thank you. I have a lot of questions for you and our earlier panelist, too, because, as you can see, there's the longer-term planning that they talked about, and then the price and the costs associated with the shifting in the resource mix. Then you're talking about the operational and market signals that's hitting, in the sort of real time, or day ahead and real time, and there's lots to address there. Next up, how the consumers really see the reality of this and more from a vertically-integrated utility perspective. What do you see the future look like in your system, and maybe comments of the relevance for the rest of the country, or at least the system in North America?

THIRD SPEAKER: I've been worked a lot with our customers, especially all of our key account customers, this past year, talking about carbon-free energy and their goals, and essentially. we all have goals. Our company's goal is trying to be net zero by 2050. Our customers have goals. The challenge is, their goals are usually a lot sooner than what our goals are. One of the things that I talk about, though, is that unless we see a path, we're very reluctant to set a goal. As we were working with our modeling and getting through things we finally could say, hey, we see a trail to getting to 2050 with today's technologies and moving forward. The questions are: How do we now make it more economic? How do we make it more resilient? How do we ensure it stays affordable as we go forward? But we saw that way of getting to 2050, so we set a goal, also for the interim target of 50% reduction of our 2007 carbon emissions by 2030. We hit that in 2020.

It's interesting if you look at our journey a little bit. In 2007, 21% of our capacity resources were carbon-free or carbon neutral resources. Today about 34%. So 15 years later we've gone from 20% to 34%, being carbon-free resources. By 2030 we're looking at being 45% carbon-free resources, and well into reducing our carbon emissions to about our 50% target and beyond to our net zero target. It's been a journey that required bringing in a lot of different resources. The key, when we started actually going back to 2007, has been nuclear, and we're actually right now in the final stages of hopefully bringing our nuclear project in Georgia into commercial operation in January. That will bring a huge amount of carbon-free resources, and also gives us that 365, 24/7 generation out there that we need so much to mix with the renewable resources.

Here in the Southeast, of course, the sun shines a lot. Wind doesn’t blow quite so much. So we're looking at new technologies to bring wind in. We've been talking to customers, and it's been interesting. This past year we worked with EEI and WRI, looking at carbon-free energy, and some of the customers, they are interested in trying to say, hey, not only do I want to be carbon-free on annual basis, but they want to be carbon-free on a 24/7 basis. How do we take our utility planning, where we're responsible for making sure the overall grid is operating, making sure it's reliable and resilient, and fold in these customer goals and actions out there, and do it where all customers are able to benefit? We’ve been trying to figure out how we leverage these customers that are willing to lean in a little bit more, faster than our goals, faster than what we'd say is probably economic for all customers, to advance our targets out there. We learned the kinds of programs and certain resources that customers would buy into. It's giving our regulators some certainty of what the demand is out there, to the point right now that by 2025, we'll have about 5,000 megawatts of solar up on the ground in Georgia operating plus other solar throughout our system.

We're moving down the path of adding a lot of stuff. The key is then, if you put together a project that aligns with the renewables that we've been adding, is, it's got to be economic. That's our regulators first question. If it's economic, they're all for it. But if it's, more like a policy objective, it's got to be made sure, that this is economically what we need to be doing. The good news is, we've been able to advance our carbon-free profile by doing things that are economic, which means our customers are benefiting on that. My colleague will address that next.

What we've also been doing with the Southeastern energy market scene is basically figuring out, how do we evolve our market structure, and add other features to it out to best increase the economics? We're seeing a lot of customers that come in wanting more renewables, wanting to be faster. With the supply chain constraints that were mentioned earlier being the reality, how do we basically match up the demand from customers, especially large C and I customers wanting to do fast and renewable, with actually how fast you can bring it onto the grid and balance it out with all of the customers.

We definitely agree with the first speaker that the IRA has definitely improved the economics of transition. But as you move faster, you now bring in new constraints. Operationally, how do you manage all this? One of the topics that arose this past year in our integrated resource plan and our rate case here in Georgia is, we need a DERM system, a distributed energy resource management system. If you're going to have more distributed resources out there, you got to know what they're doing. And it's a very big change in mindset from doing the top down planning that we've all grown up with, to how do you have a much more distributed planning out there. It can work. But it requires new infrastructure, new communication, new working together out there.

What I've found interesting as an economist in talking to other groups while leading the demand planning part of the company, we have a whole other group that does supply planning in the company. Historically we've had this great flexibility of our supply system. You could press a button, the combustion turbine turns on, and the grid stayed reliable. Now we have in minute resources. We have resources that are energy constrained. They tend to run with the sunshine, or when the wind blows, and all of a sudden, our supply side resources are a lot less flexible than they used to be. In my mind as an economist, supply has gotten less flexible and more inelastic. How do I counter that? Well, it's on the demand side of the program, and I've really got two options out there. One, can I increase demand flexibility? That's the things we're all familiar with, demand response, distributed energy resources, especially looking behind the meter. I don't have to deal with some of the grid complications there, but just how do I reduce the customer's load, but allow them to still operate? But for me as a grid operator, I'm seeing reduced load out there. So I essentially have made that demand more flexible. The other issue is how do we make demand less volatile? Because if we can make demand less volatile, it makes this planning construct a little easier, but with intermittent resources, resources that are constrained, that volatility of demand makes that planning problem more difficult.

The IIJA and the IRA both have dollars to help this. Twenty-five percent of customers in the Southeast are low income and live in poorly insulated homes. From a grid standpoint, that means that load is spiking all over the place, because there is no thermal shell there to help regulate those temperatures, both in the wintertime and in the summertime, which, by the way, I will remind folks, too, we basically now are both summer and winter peaking. It's hard to distinguish with most of our reliability risk in the wintertime. You don't think about that for the Southeast as much. We're starting to think about supply being more important, adding more carbon-free resources, but also really thinking about working with our customers with these programs to help do more demand response. Part of what we wanted to leverage there, we did this in this past year, is a distributed energy resource program that allows us to put generators out there for customers behind the meter and use them for the grid resource we need. Customers are really interested in this. And as the moderator mentioned, customers are concerned with resiliency. And customers are going like, well, gee, I want to have a generator. And if I can use it for the grid's benefit, I make resiliency cheaper for the customer, and I make the grid more resilient and more reliable. We're thinking about solutions like that. And as I mentioned the IRA dollars and really trying to work with a lot of our local stakeholders. But how do we get those dollars spent? Make sure any dollars that come out from the federal government get spent and get to the customers out there. Bottom line is, how do we transition? We've got to keep improving the economics. The IRA is going to be really important in that, and we're digesting a lot of that right now to seal up things, new technology, storage especially. As we look at new solar coming in, it's got to have storage going with it, but ut it's got to be longer-term storage. Long-term storage is going to be extremely important.

And now I'll hand off to my colleague to talk about how regulatory innovation has been addressing these issues. How do we innovate around our market environment down here to continue to evolve what brought us to the dance and keep growing with it?

FOURTH SPEAKER: The exchange market for SEAM was, is a simple exercise in many ways. Can we effectuate and capture the economies of scope and scale of RTOs, right, what they're after, and their large footprints and dispatch, and the benefits of economically and reliability, and all that good stuff, without, though the bureaucracy and costs, also upsetting the high functioning regulatory infrastructure that we have in our region? Then we generated this structure around 15-minute interval trading, all on an electronic platform, zero transmission on all of these trades that occur, no cost to transmission across. I'll get to the importance that in a minute. Then we use a split the difference process, not a top of stack, where, we flow through the cost of fuel, each resource, directly through to customers. Split the difference was really more reflective of the way our markets work now. It's all built on top of bilateral contracts within the bilateral process. So how do we unleash competition and find the cheapest kilowatt hour at any time? If you think about it, what SEAMS was supposed to do then and does, and we're already seeing and excited about it, is remove constraints like transmission costs, find the cheapest machine that's running at any particular time and make sure it's on. We're seeing evidence of that already.

The other big thing we talk about is solar. Three of the top six solar developing states in our region, North Carolina, Georgia and Florida are piling on. We have, what, 5,000, I think, on the ground now in Georgia. We have another 10,000 in the last IRP. Florida is piling on, and of course, North Carolina. That resource is likely to land on us, and we wanted to get out of the way of it. We wanted to ensure that we are not curtailing it, because curtailing it means that we don't see the environmental and economic benefits. Right? If we have to turn it off, and just in the cost of the asset perspective, it's more expensive. I don't get the cheap zero cost, variable cost energy off of that resource.

So if I can get out of the way of it, and that means zero transmission. The biggest concern that we're seeing and learning from frankly others across the country on these is shoulder and of- peak times. You're over producing, and got no place to put it. We did not want to be in that situation, and frankly, we're not in that situation in the region right now. If you think about the way the system's built and has been built over time, it's built for peak times, both transmission and generation is built for those winter and summer peaks. It's in those off- peak times. We feel pretty good about the amount of infrastructure we have on the transmission side. So right now, what we expect to happen is, instead of having to turn a resource off because we can't get it out of one region or another, it goes to another region, and it's a big region. It's 160,000 megawatts right now, from Savannah, Georgia to Springfield, Missouri, two time zones, a couple thousand miles. There's a lot of opportunity, and lots of load sinks in there, too, if you look at some of the large cities in our footprint. Looking way ahead, we're trying to get out of the way of solar, because we know we're going to get lots of it, and we know one of the issues that we've seen in a lot of places is curtailments. From our perspective if we can keep from curtailing it, it's cheaper. If it's cheaper, we get more of it. Right? I mean, it's just a simple math here on that. Avoiding curtailments was a big part of this process as we look down the road, and of course bringing in those economies of scope and scale to customers right out of the bat.

I'll end with three ideas that we're already contemplating, and utilizing SEAM for future work. One is, of course, we're looking at 5 minutes versus 15 minutes. You know, the more, the higher the penetration rate of those variable energy resources, the more likely you're going to need more granularity to your dispatch and your visibility. We assessed and it wasn't quite there, based on the penetration rate we had from the cost to deploy it. But it's on the drawing board. The other is a zero-carbon trading product. If you think about SEAM, we now know, if I put in a bid from a particular resource, I know the cost of that resource. I know where it is coming from. If I know where it is coming from, I also know the environmental profile of that resource. In a binary more simplistic process, does it have carbon or does it not have carbon? Southeast has a lot of hydro, has a lot of nukes, and has even more solar. The amount is not right quite yet, but we're looking ahead, and as we get more customers interested in it, and maybe a short-term solution. Of course, we can build or buy those resources. You can PPA those resources, and then in the short-term, you could go to a market and see if there's an opportunity to buy those resources as well. So zero carbon with the same sort of clearing process as the current SEAM. The third oneis what everything we seem to be talking about these days is, how do we build more transmission? From a transmission perspective and SEAM, I will know what deals I cannot consummate because there is no transmission capacity. I can go back and look at the data. If it did not sell because there was a transmission constraint, that is data I can use to assess the economic benefits of additional transmission. If I can assess the economic benefits, I have fodder for IRP processes in my neck of the woods. Right? will tell you right now, we're not seeing that, and you know, it's been pretty mild in the Southeast, so we're not seeing any of those transmission constraints that we don't frankly expect any in the near term, but it could happen. And now we've got the tools and the data to assess it. So that's something we're looking at. It's already on the drawing board. It'll take data to assess and understand whether that opportunity there. But, we're all trying to evolve with the resources and make sure that customers see the full benefits of those, not just environmental, but economic. We should then figure out how and if and where we should build more transmission. This should give us a lot of data to do that. So I'll leave it that. That's sort of a super high-level primer on SEAM, and there's a website out there, if you need to know more, and we are adding four more entities in Florida next year, so we'll be north of 200,000 megawatts across the region, and a pretty amazing footprint from sort of border to border. So thank you.

MODERATOR: Thank you. I’m really glad that you brought up the role of demand side resources. We have lots more to talk about. And of course, the role of storage and transmission, which, again, I think each one of these topics probably deserve its own HEPG session. It'll be a very interesting discussion after the breakout.

FOURTH SPEAKER: Really appreciate everyone being here. And the comments of all of our previous speakers. Clearly, we've got a few things going on here in ERCOT, which is not the only region in Texas. We have MISO, SPP, and the West as well, so we can't neglect them. But the vast majority of the customers in Texas are in ERCOT, and as you all know, winter storm Yuri was an eye opener for us. We had some very unfortunate deaths around the state. But it also has moved the grid and resource adequacy to the front burner. Rightfully so I think.

In the face of the changes that we've made, we broke demand records this summer 10 different times, and we rose to an all-time peak of the 80,00- megawatt, 80,038 megawatts on July 20th, not for too, too long just between the hour 4 and 5 pm, but it's indication of our massive load increases, 8% according to ERCOT over the last year with no end in sight. We also set a weekend peak demand, when it's supposed to have a lot less power, of 77,000 megawatts.

We have a system that has lots of intermittent resources, lots of dispatchable resources, and lots of challenges, making them all work together and looking over the horizon with a bunch of issues coming our way. I will briefly go through what we've done to date, just so you know, to address some of these things. We've been very, very active, both at ERCOT and the PUC. In the spring of ‘23 we will have a new ERCOT contingency reserve service, which will help specifically address ramping issues. It's probably going to be too small for what we need in the market, but it's a good start. We have a new fast frequency response service. Obviously, the frequency issues associated with intermittent resources or IBRs is something that we're trying to address with this. We hope these two new services will address the resource mix. We're going to start providing compensation for voltage support. Texas is one of the few regions that don't support or provide support for that. We're, adding loads to our non-spinning reserve service. We've created a firm fuel product. We've reformed our emergency response system by adding additional resources to it. These are all things that are in the market or are closely going to be in the market to solve an operational component of resource adequacy.

Now we think that there are a handful of challenges here. I'll speak for myself that I don't believe winter storm Yuri and our outages here were a market design failure. They were a handful of other failures, but not specifically a market design. And that does not mean that we will not have to address the market design going forward. As you know, that's where we are spending a huge amount of time. Before I get to that I want to bring up the great support from market participants in our Aggregated Distributed Energy Resource Pilot Project, which will be about 80 megawatts behind the meter virtual power plant pilot project that will begin in 2023. It will be capped at 80 megawatts around the state. This involved industry, ERCOT, and the PUC pulling together and getting this done in a matter of months, which has been a great signal to regulators and the market that we actually can solve problems together.

I have one more thing before I get to market design challenges or market design issues, and that is transmission. We've historically been a pretty good builder of transmission in ERCOT. What we haven't been is a builder of transmission for economics. To solve economic congestion across the state, we have implemented a process for that at the commission and expect the first plan identifying constraints in the ERCOT system that can be solved economically to come out by the end of the year or early in January. We are excited for that because we've had what we call generic transmission constraints. We've had about 15 of them over the last decade that have not been resolved, and are costing consumers a lot of money. We are now getting back to brass tacks on trying to figure out how to solve those, and we'll have data to prove which ones are our most economic. The goal is not to solve every constraint, but just the most economic, costly to consumers. We've solved some generic and transmission constraints with one other tool that we have, fairly new to us, and that is ordering transmission. We ordered new transmission lines into the Rio Grande Valley. We ordered a second circuit hung on an existing structure, and we've ordered a new 345 line to be built. It will be in by 2026, early 2027, but ordering it is new for us. We don't have to wait for things to become a reliability problem or a resiliency problem. We can order them ahead of time, and that's something that we're excited about as we go forward.

So that leaves one area, and then I’ll throw out a little something controversial that I think is ripe for some discussion. We've been working on new market designs for the last year and a half. Do we keep the energy only market? Do we have a load serving entity reliability, obligation, a forward reliability mechanism, a performance credit mechanism, which you may have heard about is a fairly new idea, a backstop reliability service, or dispatchable energy credit program? All of these types of market designs that have been implemented in other regions, or do we go with the Texas flavor of trying to solve our resource adequacy issues and doing it in our own way. We find ourselves twisted up like a pretzel, quite frankly, between these, trying to figure out which one is best, which one will solve the immediate problems, and which one will solve longer term problems. And we are studying these. They all have a cost to them. Generally, not one is way more expensive than the other. So what we're trying to do is thread this needle and decide how much insurance in terms of resource adequacy do we want to buy for our consumers, and how much is too much? And as you can imagine, across this 80,000-megawatt system, we have a lot of different opinions on that. Industrials clearly want us to buy as little as possible. New loads coming to the site want us to have an adequate amount. Consumers are cost-driven on that. All of these things could solve the problem. It's just a matter of at what cost. And I think we will continue to work towards this for the next few months as our legislative session gets under way in January. So those are kind of broad, high overviews.

The one thing controversial that I wanted to just throw out there, not speaking on behalf of any entity, but as a thought is federal siting authority. I have been down that road before helping design the National Interest Electric Transmission Corridor. I think we are biting off more than we can chew in this regard. I think we continue to get put in a position between state regulators and federal regulators as we talk about this broad federal siting authority structure. My recommendation is to look at it more granularly. If you all think about this, we don't want more than one big grid overlay, one high capacity system. I think we ought to be thinking about it in those terms, that we have one high capacity, HV/DC overlay, which will limit the amount of federal siting authority which could be utilized. Everything else that continues to go through RTOs would be at the state level, including 500, 765, and 345 and lower. All of that would be at the state, but you would have one federal system that would have federal siting authority, one and done, and you're over with it. And that would allow us to build a high voltage, perhaps direct current overlay shared by the United States, so we could share resources, and we'd be done with it. And then we could get back to solving the lower builds in the existing regions. That would allow a much grander spread and integration of renewables across the United States. There we go, batting clean-up. I think we got lots of lots of things to discuss, and looking forward to it. Thank you all.

MODERATOR: You pretty much covered everything from generation to transmission, and with lots of seeds for conversation after the social minutes, I guess. But I do want to say, I am jealous of one thing, the way you talk about this, is order the transmission. Many of us probably would love to be able to order the transmission. I know what you mean in ERCOT's context, but it would be really interesting, and perhaps when we come back, we will talk more about the challenges associated with transmission, as well as all the market design topics that you brought up.

AFTER A 10-minute break, the group resumed for open discussion. To maintain anonymity, participants asking questions are not identified and speakers who answer each question are just listed as respondents in order.

MODERATOR: OK, we're back in the larger room. And immediately we have hands raised.

HEPG PARTICIPANT: There's an issue that most people here are well-familiar with, and if we don't want to dwell on it, that's fine. But within FERC and the RTOs, there's been this small issue about these incentives, and minimum offer price rule, in other words, a policy where if a policy changes the cost, makes certain resources cheap, and then that presumably lowers prices and affects other resources, should FERC and the RTOs essentially try to mitigate or undo that? Just curious of the speakers' perceptions on that issue. I feel like it's not over. And obviously the IRA had a big influence on affecting those prices. Is there any reason that wholesale markets should try to undo what the federal government, I think, consciously tried to do, which is make certain resources cheap?

RESPONDENT 1: I would say that's absolutely the intent of Congress and the federal government. And so, to undo that would be quite counterproductive. The real question is whether or not our electricity markets can react to price shocks, whether it's natural gas price increase or decrease, or changes in the cost of capital, or new policies that shift the relative cost of these technologies. They're all just price shocks from the market perspective. And a well-designed market should be able to accommodate a price shock. So if capacity suddenly gets much cheaper because natural gas prices fall from $7 to $2 or whatever, capacity markets will reflect that development, or should in the next round of bidding. And the same is true if new entrants are partially subsidized by federal subsidies, or existing resources in the case of existing nuclear plants now with the PTC. I've never really understood the economic logic, or at least the reliability concerns raised around the MOPR conversations, because basically what that is, is an indictment of our current capacity markets as unable to respond adequately to price shocks, whether those are induced by policy or anything else. That's the case. That's the issue. And maybe it's a questing of timing. Right? These are stark changes that happened overnight. But that's also true for global price shocks and changes in the inflation rate and everything else that we have to deal with. So I think that's where the focus needs to be going forward, on the market design mechanisms themselves. And they should be responsive to the direction of policy, not fighting against it.

RESPONDENT 2: I'll note that SPP does not have a capacity market. But I think the question more broadly is incentives like PTCs that do influence what we're seeing, you and we talked about the negative prices; you are getting signals. Right? But we also have barriers, and we noted that in the chat, that yes, you've got a signal. Storage would be really valuable to deal with some of that. Or demand. But we're in this sort of gap period where if it's gotten behind some generation interconnection queue, we're not going to see some of that solar, or enough solar, or storage. It could be 2025, 2026. And so you're going to have to live with some of those negative prices until you get there. So that's generally how we see the interaction, is generally when you see the price of the renewables manifest itself in the markets.

MODERATOR: Yeah, the panelists actually are from markets that don't have a centralized capacity market.

NEXT HEPG PARTICIPANT: I mentioned in the breakout, as a recovering market designer, to take my questions for what they are. I listened to the conversation about emerging desires amongst corporates to not only get sustainable energy, but maybe to get it on an around the clock basis. There's at least a couple of companies amongst my peers that are talking about that. But then thinking back in my own history, I'm a big believer in the huge economy of scale of planning and operating a grid in as large a scale as is feasible. And you can argue about what's feasible. Think RTO scale, think utility scale, right. Bigger is better, at least as it relates to economies of scale. Don't we run the risk of, by planning from the enterprise up, instead of from the grid down, don't we run the risk of doing things that might be, at best, inefficient, and at worst unreliable? Maybe there's a better way to think about this.

RESPONDENT 1: You raise some good points. Conversations we had this spring, it's kind of interesting, because we had some customers around, it was a Chatham House rules thing here, too. I'm going to allude to different viewpoints, but not attribute. But there were some in there that very much were wanting 24/7, be able to say that's what they're doing. There were some just kind of going, hey, I just want to be carbon-free. It's kind of interesting, one of the things we got to talk about a little bit with some of the customers, because there was a lot of huge education components. And to your point about sort of this bottom up optimization, versus top down, ours covered, and it's kind of on this question of, what do you want to talk about as 24/7? You get 80% of the hours covered? Or 100%? You start getting to 100%, you start sub-optimizing, and that was the conversation we started having with some of these customers that really wanted to go 24/7, and have people understand. My question to a lot of those customers out there was, OK, you want to have more of your hours covered. How do we leverage that? And if you're willing to pay a premium on that, maybe we're able to bring new resources on quicker, which do benefit the overall grid. But I think you're right. If we start trying to get 24/7 to every individual profile, especially early on, I'm afraid we're going to suboptimize, and mess up the economics for the customer. So, there's a balance point there of, how do I help this individual customer advance their goals, but also do it in a way that doesn't hurt the economics for the rest of the customers? That was a lot of the dialogue we had this spring with the customer groups. Some of those customer groups when they start to understanding that, they want to achieve their goals, but don't want to make it expensive for all the other market participants out there. So you need a big education component in all this dialogue.

HEPG PARTICIPANT (follow-up): And just to be clear, my question is not implying that my company isn't interested in getting to a zero-carbon grid. It's a question of, what would be the most reliable and efficient way to get there? And is it for me to have an accounting mechanism that says I'm carbon-free on my own, and we start adding those up. It feels like that's a re-Balkanization of the grid.

RESPONDENT 1: Potentially. The other part I would say, though, is, and this has been some of the conversation we're having with some of those customers, to the extent some of those customers have the ability to respond to carbon price signals, around where we do slow the grid, when the carbon price signals are higher. That's where we had some opportunity. And this is some of the dialogue we had, too, of those customers actually doing stuff on their demand piece of the puzzle, and we could match that with some of the supply pieces to get a lower overall carbon footprint, which that would have been met. It's a thorny, important question.

RESPONDENT 2: At ZERO Lab at Princeton, we've done the first system level modeling of the impacts of hourly procurement. We've modeled different shares and commercial investor loads, procuring 24/7 products at differing levels of matching. In our first study, and then in the second study, we focused on the role of time based energy attributes to trade between different load profiles and allow for effectively the market to aggregate the demand profile so that you're not trying to meet every individual person on their own. You're doing that through a market trading scheme. In some ways you're reinventing the wholesale market. Right? To do that. And so it is true that this is going to be sort of the little subset of the market that's operating as if it's an island. I just want to stress, the purpose of that is not just an accounting mechanism, or not just to reduce your emissions to zero. There are lots of ways to reduce emissions, and this may not be the most cost effective one in the short-term. The focus is really on driving forward in time demand for the kinds of technologies that the entire system needs to get to 24/7, like the other panelist was talking about. You're going to need those resources that are not weather constrained and not energy limited, whether that's a very long duration storage or advanced nuclear or carbon capture or hydrogen combustion or advanced geothermal. The whole system's going to need those in the 2030s and 2040s to reach our big broad societal goals. But if they're not deployed in the near term, they won't be ready to go when we all need them.

It's really kind of a voluntary effort to drive niche markets and technology policy goals in conjunction with federal policies like support for demonstration programs and new subsidies. That's where the real impact of those kinds of hourly procurements come from. And if that's not your focus, I wouldn't recommend that as an approach. All kinds of customers can have all kinds of different voluntary impacts in different areas. And if you want to reduce emissions for most in the short-term, it's probably not the way to go. If you want to drive technological change and create new markets, and pull technologies forward in time, and you could afford to do that, then I think you're going to have a really big impact in the long-term. That's what our study's looking at.

HEPG PARTICIPANT (follow-up): I think that's right. I would offer that the notion that different customers will have different priorities is an important attribute to continue to remember, and that to the extent that there are standards being developed around carbon emissions, that we ought to reflect on that as well, that one solution isn't necessarily the answer for all customers.

BILL HOGAN: I have a clarifying question for a speaker. That's why I put my hand up. So I will control myself and come back to this other subject later. When you were describing curtailment, you had talked about negative prices and production tax credits, and you used the phrase, economic curtailment, as opposed to the system operator curtailing. Then later you showed the graphics about the increased curtailment behind constraints and so on. And I'm confused. I don't quite understand what is economic curtailment that is not the system operator telling him not to produce? Can you explain what you meant there?

RESPONDENT 1: Yes, I will clarify. I think it's the difference between the operator actively directing through a phone call. Right? I am calling Professor Hogan to back his resource off because I see congestion. Versus sitting back and letting the market optimization make those decisions for you. Right? And what we see is that 90% of the curtailment is just redispatch. Right? It's just, the market basing its dispatched based on your offer curve, which just happens to be negative for most wind resources. As opposed to the operator not caring about your offer at all and taking it out of merit. It could be in merit, could be out of merit, but it's an operator action that overrides whatever the software may do. So I'm making a distinction between those two. Does that help?

BILL HOGAN: Yes, thank you.

NEXT HEPG PARTICIPANT: I would like to follow up on Bill's clarifying question. I had a very similar question, or at least confusion. I do, and then I have a more substantive question. I do not understand how negative offer prices could cause economic curtailments. To me, if you're the lowest priced offer by like negative $30 a megawatt hour, why, if you're not in the dispatch, how can we call that negative, economic curtailment?

I just have another question for the last speaker which has been sort of a pet peeve of mine for years now. I do not see any reason why AC interconnection with ERCOT need trigger federal jurisdiction over ERCOT. I've written about it, and what not, and I've never gotten, and only seemed to get visceral reactions that end up seemingly, usually invoking the Alamo or something like that. So I'm just wondering if you might comment a little bit about that.

RESPONDENT 1: Yeah, I think that the continued view of policy makers and elected officials in Texas will be the same, which is the Alamo, don't come mess with us. We'll mess with you when we want you. So it's not a matter of legality. It's a matter of interconnectedness, so to speak. And it's just not something that we think we need. Unfortunately, in this last governor's race, it became a political issue as well. When it gets into those, it becomes a football. It's less and less likely that those things are going to happen. But clearly, we are trying to move out on DC transmission lines and allow them to interconnect and have streamlined the process and have made it very understandable, and hopefully easy for DC interconnection with our neighbors.

RESPONDENT 1: I'll answer that clarifying question. There might just be semantics here, but I'll try one more time to answer it. With most traditional resources, the thought would be I have to get the price high enough to tell them, in order to incent them to do something. Right? So, I may have my strike price. I'll do something if the price is above this, and I'll generate. Wind resources don't do that. Right? It's, I'm going to generate until you tell me not to. Right? And most resources that are wind will say, hey, if the price is negative 30, then I will stop generating. Right? And the dispatch will say, OK, the price is negative 35. You're gone. Right? So you were going to generate at 100. Now you're going to generate at zero. I've coined that economic curtailment. It could just be economic dispatch. Right? But I am taking you from a higher point and putting you to zero. Right? And so that's just the software and economics of the situation. As opposed to the operator saying, I don't care what the price is. You're going to zero. Right? And we see both of those. But the vast majority, 90% is the software saying, hey, the price is negative 35. Your offer is minus 30. Time for you to go. Hopefully that helps.

NEXT HEPG PARTICIPANT: One of the things that we do is long-term forecasting, nodal and hourly marginal emission rates. The Infrastructure Act created a provision in the EIA dashboard for system operators to publish their nodal marginal emission rates. And other than PJM, which only does it on the resource side, so far others have not stepped up. My question is really to those who are either in a position to influence system operators or who are system operators. What are the barriers to doing that? Would you be willing to do that such that your customers, and to the extent that they want to, best reduce their emissions impact?

I also have a comment to make about the ongoing discussion about customers. While I think there is a role for niche markets and supporting early participants in new technologies, I think the data on the idea that deployment drives innovation is much more varied. You see differences in progress rates over time between technologies. And you certainly see instances where significant deployment incentives actually increase costs and not increased innovation. So, it's a much more varied picture. I'm interested in what the panelists think about how to create a broader innovation system beyond just saying we're going to provide additional incentives for technologies that are not yet approaching commercial viability? But I'll start with my first question. What can we do to get marginal emission rates out there from system operators so that people can actually know what their impact is, looking at impacts from a system perspective, of course?

RESPONDENT 1: I think SPP, in terms of agenda, is really driven by what the membership and the participants want to accomplish. And I will say that generally in the SPP footprint, this type of approach is not something that they're really concerned with at this point. However, when we look at what SPP is attempting to do in the West, this is a major issue, and it's something that they're considering quite significantly. I know one of the things they're working on with the Western folks is how to value emissions reductions and what that is within the solutions that they're doing to start to send signals. Now, the challenge they're facing is, Washington State wants to do one thing. Colorado wants to something else. Arizona's doing something different. And so they're trying to come up with an approach that can handle those different types of flavors. But what's interesting is, there's no good answer at this point, but I can say that they are working to try to start figuring out how best that that they can do that. The problem is, when you start dealing with these systems, it's that people want to start painting electrons. These electrons are green, and these are blue, and these are all these different colors. And that's really not a recipe for success. It's something that SPP is thinking about in the West, and something that we hopefully could talk about at a future session, depending on how they move and come up with things.

RESPONDENT 2: Well, I would say, and this should come as no surprise to anybody, but I think your question would probably not get a great response from our political leaders here in our state. Carbon emissions and reductions are not the primary source for transitioning the electric power system in Texas. If you looked at our emission profiles for the amount of wind that we have added to our system, the amount of gas plants over the last 20 years, our profiles have come down dramatically, especially SO2. NOX have probably come down quite a bit. And you know, we probably put up our story against anybody's. But to drive that towards the national narrative of zero emission targets, I think we would have a different narrative in Texas, and so how we would get there, I really don't know.

MODERATOR: Wow. We always have a different narrative for Texas. So that works well. But I wanted to, before we go to the next question was raised, I wondered if a corporate perspective as well added to this?

RESPONDENT 1: We worked a good bit this past couple of years with WRI and EEI. We got working with them on this carbon reporting in general on an annual basis. And we've kind of gotten that standardized. That's been a good thing we've been working on there. To your question on hourly stuff, I think what some of the innovation, for the time of your question here in a minute, comes in, we've been partnering with actually several customers trying to look, because they've been asking us that question. Can you give us that information? And I think the first part of the question, you have to decide, well, what are you trying to do? Are you trying to make hourly marginal decisions? That's one question. Or are you just trying to get more hourly accounting of the whole stack of the grid? Actually, getting an hourly stack of the grid in retrospect is easier.

The marginal question is a little harder, as we've been looking at the issue. Because what happens is, part of our work to make things economic in the Southeast has been that may be a carbon-free resource. But the carbon-free attributes to that were sold to somebody else or retired on behalf of that customer. At the margin, you're having to add a null attribute to that resource, so it looks like a carbon attribute, even though it's not. It's very confusing about what you are actually doing. Because if you actually backed off load, you're technically backing off that solar resource, which from a grid emissions stance, doing the rec accounting the right way, has carbon emissions to it, even though it's been sold somewhere else. This hourly idea of accounting, is interesting, and I did kind of agree with you. I think to some customers, it could cause them to change their operations and do some things differently, which may allow them to avoid carbon. But this issue of what we've been doing and looking at, you know, selling some of the attributes or retiring the attributes, although the customer's ascribed to a certain renewable resource, and therefore the attributes are being retired on their behalf, means from a grid perspective, it doesn't look carbon-free, which gets to be very confusing very, very quickly. I think the answer as an innovation piece of the puzzle is, as we start, it's where we try to really engage stakeholders and customers a lot, trying to find some of these things that make sense to a lot of people and then go pursue them, seems to be a safer way, rather than just trying to pick one technology as a winner or loser kind of vacuum. That's kind of where this has been going here in this conversation.

RESPONDENT 2: You raise a bunch of interesting and challenging questions when it comes to emissions claims. Right? I think I would start with making the marginal and average physical data available, and then we can work on the latter stuff. We don't need to perfect all of, just make it very clear and make legal disclaimers, so you don't get in trouble with the lawyers that these are not to be used for attributional purposes. But we could make it clear when and where high emitting resources are on the margins can drive shifting load, can drive storage operations, can drive the deployment of firm resources into those, wind farm ratios into those areas and can help customers who want to do that. I think it's a really important piece of information. And all system operators should know exactly what the marginal resources are. Are you using it for LMP calculations? It doesn't need to be revealed in real time; it can be done ex post. This is something that I think every RTO is capable of doing, and it would be very handy for large balancing authorities and a lot of market participants. There are a lot of nuances beyond that. In fact, scope two greenhouse accounting rules are under flux right now for that very reason, because there's a growing recognition that a rec is not a way to zero out your emissions. It's not an appropriate representation of what's going on in the system. And we need more sophisticated accounting mechanisms, which will in turn rely on that kind of data in the long-term. So don't let that hold you back. Go for it.

RESPONDENT 1: That's why customers who are thinking about their job as trying to drive innovation need to think carefully about the attributes of the technology or sector that they're trying to catalyze, and where they're at. Not every sector's different. I mean, not every sector's the same. And you know, you can have a different impact procuring the first modular reactor than you the first enhanced geothermal or the first metal air battery. I think you need to understand what you're doing in that space. You know, I wish we had a more nuanced and selective federal energy innovation ecosystem. But we have just fleshed out a lot more tools than we had a year ago. And in a lot more varied way, everything from demonstration funding and place based hubs, and loan guarantees of various types, and now some fairly broad deployment subsidies once those technologies make it past end to the kind. So it's not perfect. Policy never is. But we're in a lot better place than we were a year ago.

BILL HOGAN: So I want to continue on this topic, because I find, it may be that we have agreement here, but I find the subject extremely confusing. So I know how to do, in principle, the marginal emissions calculation, and just the way that was described, and the way PJM does it, and they do it the right way, and so on. That's very interesting. I don't know how you can use that for marginal load. What is the impact on emissions and the whole system? I do not know how to do the average emissions from the total of that individual load at this hour. I think it's a fiction. I don't know how we could build a system that's based on that. And I think the red and yellow and green electrons is not a recipe for success captures the essence of that idea, there, but that may not be the case.

And then the third thing is, if I'm interested in emissions, I don't care when they're emitted. What I care about is cumulative emissions over time that's going into the atmosphere around the world. And if you're reducing emissions at two in the morning, and I'm not consuming, that's still a good thing, and so on. And if I'm paying for it, then that's OK, too. So that offsets strike me as a logical approach, a doable approach, and a politically unpopular approach, because they're so subject to corruption, basically. You going to have that problem. So I just don't know, I think the marginal story just makes perfectly good sense. It also explains why the elephant in the room always is carbon taxes, because that deals with the marginal condition, and it takes care of all these problems right away. And you don't care about what the average emissions are for individual loads. That's not a problem we can answer, a question we can answer, and it's not, it shouldn't be the focus of our approach. Now, what is wrong with my source of confusion here?

HEPG PARTICIPANT: Well, I don't think there's anything wrong with your sources of confusion. I think the right way to do it is to calculate marginal emission rates. We can do it for load. We can do it for generation. We can even do it for transmission. And you know, it reflects the fact that electricity is a system. And you can't really color electrons. We get in trouble when we try to do that. If you look, for example, at what California has done, you can argue that they colored electrons coming in across the border. As a result, when they increased their carbon price, they don't do very much to reduce emissions in the West. They actually do more for emission in the West when they increase their RPS, because a quarter of their RPS can be met outside the state. And one speaker is nodding his head, because he and one of his post-docs and I co-wrote a paper on that. So you know, it really does depend upon trying to do this marginally. I wish we had more willingness to do that. I think we've gotten into trouble because we started down a different path in the way we did guidance historically, and we need to be revisiting that. But your confusion is right on point.

RESPONDENT 1: Yeah, I mean, I think you're right, Bill, that if you're going to do an emissions-based accounting, using marginal emissions rate are the most, is the most defensible way to go, and it's why we need that data available. If you're trying to drive the technologies we need to operate 100% carbon-free grid with reliability hour by hour, which is what 24/7 procurement is focused on, then you don't necessarily want to focus on the short-run marginal emissions rate. You want to focus on the portfolio of resources. You need to meet the grid demand 24/7, and you're using your load as a proxy for that. And so again, it's just different goals.

You have different objectives for voluntary action. Nobody's required to do any of this stuff. It's all voluntary at this point, although I do think it's interesting to think about augmentations to RPS or CES policies to start to blend in a share of the load that's matched on an hourly basis, if our goal is to drive some of these technologies forward in a more market-friendly way. Because then the market can respond and procure a blend of firm resources and long duration storage that helps them meet that hourly share, rather than prescribe, you know, two gigawatts of storage or one gigawatt of geothermal, or whatever else that often happens.

There are some interesting ways to think about those mechanisms. But again, it's just like when you think about technology policy versus emissions externalities. Those two are not the same externality, and they don't require the same policy instruments to succeed. We have kind of the same thing here with voluntary actions. If your goal to most cost effectively reduce short-run emissions, then focus on marginal emissions factors. If your goal is to drive technology change for the longer term, then you know, hourly procurement is a way to do that pretty effectively.

BILL HOGAN: Well I got everything except the last phrase. So I don't understand what it means. I think technology policy and doing all that is very important, and it's a whole different set of instruments. But it's not me, here in my home, buying green energy to cover my total consumption right at this moment.

RESPONDENT: We do. I mean you have to match your, you need instruments that allow you to match production and consumption in time. Right? Which is not a difficult thing really to do. We just need a real an energy attribute that's minted every hour or every 30 minutes, or whatever time increment you want, as opposed to monthly ex-post.

HEPG PARTICIPANT: So, you're in favor of coloring the electrons, and you think that works?

RESPONDENT: No, I think this is a temporal instrument. Right? So the idea is, if I buy a 100, if I can match 100% of my consumption with temporal attributes that match my consumption at the same time, and that demonstrate deliverability, it's effectively the same as if I'm operating my own system over here that is meeting all of my needs. It's the same physical impact on the grid, as if my load just went away along with all that generation. And we can show that with those instruments. And if your goal is to pull markets forward in time that look like what the future needs to look like, that's one instrument to do that. Not everybody needs to do that. Not everybody should do that. But if that's your goal, it's a way to do it.

HEPG PARTICIPANT: I think there's a there a foundational difference –-

BILL HOGAN: There's a key word in there. Deliverability. Show deliverability. So it's an unanswerable question.

RESPONDENT: No, it's not. You know, all you need to do is show if there's a congestion difference between the two nodes. And which one is higher, and which one is lower, if so. If you're on the downstream side of the congestion, then you're fine. You don't need to route this through the system. You need to use congestion that would split the market, right, into different marginal generators. And you can tell.

RESPONDENT 2: I do agree that I think, with some of the customers we've talked to, it has spurred a conversation of, OK, how could, what technologies would I need to think about to really get me to 24/7? And I, that has been an enjoyable conversation. I've had some other conversations where it's been a customer or other utilities, instead of taking a one-off opportunity to get a customer a very high percentage of hours being covered, but it's not really repeatable. And that's where I get a little more uncomfortable, which I think, Bill, it’s kind of getting to your point of, I'm not sure of this 24/7, I think. It might be an interesting little thing to kind of spur to odd innovation, as Jesse’s saying. I’m not sure, it's more of a boutique kind of item to spur things, and it is a broad market kind of item out there. That's kind of where I kind of look at it.

MODERATOR: I want to jump in real quick. I just have to insert myself a little bit, really, for our speakers, kind of on this. You talk about driving development, and you asked the question, well, if your goal is to accelerate the deployment of, sort of sounds like long duration storage or other technologies that can have this 24/7 matching, then this is an approach to do it. But my question is, do the customers really think that way, and therefore want 24/7 matching of green energy to their load? Or is this just something else that’s It's like, now I can say I'm Google, therefore I have 24/7? Is there really a driving force from the consumer perspective of technological innovation? OK, I see a nod, and I see a shake of heads

RESPONDENT 1: That depends what customer you're talking about. I mean, for Google and others in the first mover coalition and the federal government that's doing this and others, that's very clearly their goal. And they're already signing long-term contracts with enhanced geothermal and long duration storage and portfolios of short duration storage and demand flexibility through AES to make this work. So yeah, that's their goal. Now, it's not what Bill or the average customer or anybody wants to do for their house, although there are community choice aggregators in California that are exploring, doing this at a CCA level, which would have a similar aggregate impact. So yeah, again, it's an option that that if you want to increase your impact on the transformation of the electricity sector, this is a way to do it beyond procuring offsets or recs, which are the current tools we have at our disposal. It's not what everybody is going to do.

HEPG PARTICIPANT: Can I just add, because it's right on point. I want to add my comment, if that's OK. One, I don't think what is being described amongst the first mover coalition or others is mutually exclusive to the notion of transforming the grid in other ways. I don't think these are mutually exclusive strategies. I want to be clear about that first. But second, I think there are different views on what makes the most impact, because there is a temporal element to this, and I don't mean hourly. But I do mean temporal in the sense that to the extent that investments today can reduce carbon emissions more per dollar invested based on when you, what time of day, or how you invest those in carbon emissions reduction, it's actually more valuable to reduce more carbon today than it is potentially to introduce new technologies, in the sense that carbon emitted today has obviously a longer lasting impact on climate change. And we can debate about whether investments in new technologies might advance the transition more quickly. But there's no debating that carbon avoided today is worth more to avoiding the worst impacts of climate change than carbon avoided tomorrow.

RESPONDENT: That’s right. But if you have a limited budget, and you’re trying to maximize your impact, if you can succeed in taking a technology into the market and down in price by 50%, the follow-on investment that that can spur is likely to have a much larger impact on emissions than your entire portfolio of emissions. Right? So this is like Denmark.

HEPG PARTICIPANT: The key threshold question is, if you can be successful at doing that, and I can tell you that, I can say with a 100% certainty what might be a greater impact on carbon emissions. The dollars spent there are a 100% certain to have a greater impact on carbon emissions. Whereas an investment in an unproven technology to try and prove it has a much lower potential to make an impact. So we can debate about where the right dollars should go. But to your point different entities will have different strategies.

RESPONDENT: Yeah, I just don't, you made a normative statement about which was clearly better. And I think, to your point, it's going to be a different set of strategies pursued, depending on your goals. Right?

HEPG PARTICIPANT: I have a concern about the Inflation Reduction Act. I understand the constraints because we're not pricing carbon, and that's the big absence. My question is, at what point do we move beyond just throwing cash at various technologies, some of which are promising, some of which have political influence that may not be so promising, but all of which will over time claim it's an entitlement? If you look at some of the debate about net metering, you look at the debate about production tax credits, even as the cost goes down and the technology is viable, we're still having the folks that benefit from that want to cling to that as if it's a property right. And how do you deal with the politics of trying to end that and really trying to develop and maintain an efficient marketplace? And so that's one of the flaws that I see in the approach of the Inflation Reduction Act. Unless, of course, the big thing that would change that is if you actually had some kind of price on carbon. That that would change things dramatically. But in the absence of that, what do you do politically to get rid of this notion that it's my proprietary right toe have net metered? My proprietary right to have production tax credits? Those sorts of things. How do we do away with that and move in a more efficient direction?

The other question is on a different subject, from the speakers' perspective on siting. I don't understand how we can develop a more responsive siting system, if you don't have some kind of federal role? I mean, the role of the states is, first up, half of the states don't even have siting. But those that do or manipulate it, Ohio, for example, just made it much, much, much more difficult to site wind projects than anything else. By law they did that. There's this whole controversy in Maine, with building the line from Quebec down to Massachusetts, where basically the fossil folks suddenly became green and said, this line will destroy the Maine forest, and so, therefore we have to defeat it. This is winding its way through the courts, and the effect of what the fossil fuel guys did, I think it may end up, they lose, their losing so far in the courts, but it remains to be seen. But I don't know what you mean by a more granular approach to siting, because we already have a granular approach, and it's clearly not working very well.

RESPONDENT 1: My view is just very specifically that, like our interstate highway system, we only have one interstate highway system, be it it's pretty robust. If you've looked at all of the grid overlay ideas over the last 15 or 20 years, we did one in in 2001 with the National Transmission Grid Study at DOE. SPP has done them. Siemens has done them. AEP has done them. I mean, they've been done over and over. They only show one overlay. But what we're trying to do is we're trying to fight this Federal siting, you know, state siting jurisdictional issue, when it comes to like all the lines, all of the higher capacity lines. And what I think is, we ought to just try to solve it for one, one set of lines first, and that will drive challenges and solutions that we can address next. But if we are just trying to be open-ended about it, I think we're going to get very little movement from state commissioners in giving up that authority. If you do one project and allow the federal government to issue that as a concession, then I think you're going to get very low cost of capital, and you'll get to build these projects.

MODERATOR: When you say one, just for clarification, do you mean as a country, let's come up with like the high voltage overlay and determine this is what we needed, and for that we wouldn't have subject to federal permitting?

RESPONDENT: Yes, that’s it. And every other component of siting, whether it be in the RTO plans or in vertically integrated states, is all left to the state commissioners to work through their citing regimes. We're not trying to solve every problem in the book. We're just trying to solve a few of them.

MODERATOR: So to make that practical, the next step is actually to agree to what that bundle of national overlay might need to look like, and that agreement has to be determined at the national level? Do states have voice on that? Just curious.

RESPONDENT: I don't know the answer to that. I would say, we need to have creativity that's thrown into this, rather than just plain old electric transmission planning. And that would be for the federal government to go out with a RFP or some kind of a concession, and let people partner up and figure out what it looks like. You know, to find the structure of it. I mean, the fact of the matter is, we haven't built that much in 20 years. We built a lot of intraregional transmission intrastate transmission, but not interregional. So I’m just on it out as a new idea, as a new way to solve the problem, which would be, solve one problem at a time not, muddy the water for one problem by combining it with all the other transmission.

ASHLEY BROWN: The potential for litigation over what falls out from the one time federal action becomes enormous.

BILL HOGAN: I just want to follow up. I thought this is a very interesting suggestion and one of the things we know is that if you're that high voltage grid across the whole country story is going to come in stages. So it's not all going to be built overnight, the same thing. And one way to cut what you're talking about is just to do it not in terms of this overlay story, but just a certain level of voltage, like very high voltage. Stop. That gets mandated by with this as the vision of where it's going, but it comes through in a sequence of stages that we learn and adapt as we go, to change the jurisdictional story, to apply only to very high voltage transmission expansion. So that would that work?

RESPONDENT: Maybe. I don't know. I haven't seen anything work to date. So it might. I think the higher, the vision that I would say is that the higher voltages you go, whether they be AC or DC, the fewer components of that that you need across the system. I you just focus on those few components, you're narrowing the scope of federal siting authority, so that this argument between state commissioners and federal commissioners narrows. That's kind of the area that I've been thinking of.

ASHLEY BROWN: Institutionally, though, the irony of the thing is half the states don't have siting authority so it falls to local county governments and city governments. Or the utilities do it, or whoever's building the transmission does what they please, which is rarely the case? Or alternatively, where they do, what this ends up being is, it's a commercial game, not even so much the state regulators, the deciding regulators. It's a commercial game between various interests that want to build up walls to protect their own zone of commercial interest. And so it's hard to how you get around that.

RESPONDENT: Well, that's where I suggested you create something like an EWG at the federal level, where you are exempting them from state law. You're exempting them from state markets. You're, so what you're trying to do is create the higher-level system by defining what it is in very narrow terms. But they're really not going to be a, they're going to look, if it's DC, they're going to look like a generator in a handful of markets, and that's it. And again, just throwing out food for thought that we've been thinking about this too broadly, and maybe we ought to think about it narrowly and get one of these done before we think about the second.

Can I say one thing about federal incentives? So it's one thing that we're struggling with here in Texas. Obviously, a lot of these incentives are driven towards the generation sector. We don't have a regulated generation sector in Texas, for the most part, but our transmission and distribution is. It seems hard, in my opinion, for regulators to figure out how we are going to get utilities to buy into free federal money when it's going to reduce their return on investment. If we in Texas would think about it differently and say, maybe we should just take that federal money and reduce the debt side of the project, and keep the equity side the same, so that the utility is agnostic to the amount of equity that they're putting into a project, but you're encouraging them over time to try and get more and more of these federal dollars. There would be a cost initially. I think consumers would definitely challenge it at the beginning. But if the story gets driven over the long-term, federal dollars are not going away. I think we've seen it's happened three times now. It's going to happen more and more, is my assumption. We ought to have a regulatory strategy that allows utilities to go get that money and be agnostic.

ASHLEY BROWN: One of the things that's interesting about that question is, what a lot of utilities have argued over the years, they can't be particularly innovative in regard to technology because they've had prudential reviews going on. And so they view it as a disincentive. And so to some extent, whatever grant you get could obviate, does obviate some of that risk. But the other thing, and the other thing that's interesting about it is, it's sort of the opposite of what I said before, which is that, you know, once people start getting these grants, it's become some entitlement. It's a property right. And so therefore it becomes very difficult for it to fade away and move more towards market mechanisms. What you're saying is, if I understood you right, it's from the standpoint of regulated utility, maintaining that it's a disincentive. Utilities have an incentive not to take the money, and instead to invest their own money.

RESPONDENT: Well, that's what I say in our market. I'm not saying that across all markets. But in Texas, where the utility is just a transmission and distribution utility, we would like to get money, federal money to help projects that improve our distribution systems for electric vehicles and understanding distributed resources and other things. And the question is, how much of that is going to, are going to get pushback from the utilities because they are not going to be able to put all of that money into their rate base because it's going to have to be reduced by some of the federal dollars? Is there a rate scheme that we could put in place that would make them agnostic in that space and really encourage them to go get this money every single time? I'm not talking about one time. I would want to find a way where I could get my utilities in Texas to go get that money every single time.

MODERATOR: I just want to add that that's a really interesting perspective. In Massachusetts, I have not heard our utility be less than enthusiastic about the potential federal funding for increasing, or improving grid reliability, etc. That's interesting.

RESPONDENT 2: Let me jump in there. I mean, I would say, we have launched, we have clean, safe, reliable, and affordable. And we're looking at a big bill to transition the fleet both from, from an T&D perspective but also from a generation perspective. I think the question that we're looking at, and I think it's an appropriate question, yes, there's a business model incentive for utilities to invest. That's how we invest to grow the grid, make sure it's reliable, and here for the long-term. However, keep it affordable, socializing that cost to the federal government. I mean, it's not that the federal government just magically pays for it. It is getting socialized through the taxpayer mechanisms out there. But there is a question of, if we had decided as a society that we need to reduce carbon, we need to transition the fleet, then I think the society has to ask the affordability question. Quite honestly, it's probably more than enough money out there to the point that you're seeing in the utilities you work with of how do we utilize this federal money to move the grids forward? I think there's still investment incentive out there to make sure the utilities are there long-term, making sure the grid is reliable and working in place, but also making sure it's affordable to customers. You break affordable, customers aren't, it's not going to work. If we, you know, it's got to be a balanced plan. It's not an all or nothing project.

RESPONDENT 3: Keep in mind the results of the PJM study. You could see electricity rates per megawatt hour, especially for the bulk system, declining over time, with some of that cost, especially subsidies for the upfront cost of a lot of capital intensive equipment, we need a transition here being borne by the federal government instead. Now, we didn't model distribution networks in our study, and with demand going up, it's likely we're going to need enhanced investments and distribution. And so, again, I think we have utilities that are used to a somewhat zero-sum mentality about this, because demand growth hasn't been particularly robust. Maybe in Texas it's a little different in the South, where you have demand growth. But you know, we're going to start to see a lot of need for investment and a lot of rate based opportunity, and I hope the utilities are not so greedy as they don't want to take advantage of federal money when it's there because it might reduce how fast their rate grows. You know, maybe you need to think about ways to make it agnostic to that. But to your point about affordability, they should be looking out for opportunities to lower costs by deferring investments with federal funding. You know, the rate base as a whole should be quite healthy over the course of this transition, given the amount of capital that has to be invested over the next two decades. We're talking about the grid doubling or tripling, right, by 2050, in terms of the long-term trajectory here with electrification as a key tenant of basically any decarbonization strategy. And so there's a lot of growth potential.

HEPG PARTICIPANT: I wanted to touch on the issue that was brought up before about installed reserve requirements or capacity markets. Obviously very important as we increase renewable penetration and think about how do we ensure that the lights stay on? And I guess my question is for Jimmy, because you talked about instead of a capacity, I think I understood that you talked about instead of a capacity market, just putting the responsibility for procuring reserves on to loads. And I think of that as a capacity market. As long as you have an installed reserve requirement that you're going to impose on loads, you have a capacity market. It's just a bilateral capacity market where they have to go out and contact with other resources for a capacity payment so they can show that they have that. And one thing I'm wondering if ERCOT is considering, just because in general, it would be nice to start thinking about how we put the demand side more into the equation here and have voluntary curtailments, whether there is the ability to, rather than have people pay for capacity, have people sign up, whether they're firm or not, and simply if they choose not to pay for capacity or not to shut, that they have the resources, they have to arrange to be able to curtail. And whether the technology is there yet to curtail loads that are non-firm, I think we'd start to get a much more efficient and a much better participation on the demand side into these markets if we had this structure incentivized that way, rather than treating our reserve requirements the same way we always did, integrated resources planning, you know, 40 years ago.

RESPONDENT 1: I did mention a load serving entity obligation. That's not something that's really on the front burner right now. It was considered and studied. But I think that transferring all of the generation costs and resource reliability insurance, so to speak, to load is kind of the antithesis of what we did when we deregulated the market in '95. So we're trying again, to thread a needle here, trying to figure out how we get some additional revenue in the market for dispatchable resources, but not assign that 100% to loads, or at least in a way that a load serving entity obligation might, perhaps in SPP, we would address the deliverability issues and other things that would make that a challenge in the state. That's not going to be the primary resolution in Texas at this point in time.

As to the second question about demand response and loads, we absolutely want to get them more involved in our system. We've done a handful of things operationally to make them more valuable on a day to day basis and an hour to hour basis. And I think we're still pretty far behind when it comes to energy efficiency. But demand response, I think as we are allowing our retail electric providers and others to offer those services into the wholesale market, we're seeing a ramp up in those services. And we're probably at the tip of the iceberg on that one.

RESPONDENT 2: I'll further note something that is part of this equation is outages. I'm not talking about the forced outage type. I'm talking about maintenance and really this idea of when to plan maintenance. We're seeing the windows of maintenance shrink. But what we're also seeing is the need for flexibility and resiliency increase, particularly during those periods as well. And so I think it's, that's going to be a challenge on how to coordinate when those outage periods are, even just for maintenance purposes. Forget about, because everybody's going to want to take a maintenance at the same period, and that's going to be really difficult. And right now it's this first-come, first-served approach. But that's not necessarily the best use of that period. I think the way we look at it as, there are resources that are probably useless when you get the cold weather. If those resources were to take an outage during that period, that would be better, rather than sort of using this first-come, first-served approach that we're using right now. In a way, SPP has plenty of resources. It's just they're not available at the right time. And it's getting those resources available and managing this outage that's going to be critical.

RESPONDENT 1: That's a great point. ERCOT developed a new outage maintenance protocol process where generators have to apply, and it has to be approved by ERCOT. This just happened within the last few months. Clearly, we're going to see how that works. They seem to believe that their process that they've created will give more hours to the generators to actually do the maintenance than they've had in the past but spread it out over more of the year. That's been approved. It was fairly controversial among the generators, but we'll see how it works this next year when it really gets put into place. The biggest challenge is, as we call them blue sky days when we have a lot of maintenance outages, a lot of forced outages, and very low wind and solar. Then we find ourselves really in a bind, and those are the days that we're trying to solve for. And the question is, do you buy a large amount of insurance for a capacity market to solve for those very few infrequent events? Or is there a better system of tools that we can use and give to ERCOT and the market participants to allow that to be reliable and resilient?

RESPONDENT 2: Yeah, I think this is a really key question, and where I think we do have reasons to be skeptical of the current capacity market constructs, given their kind of lack of granularity. It's not the peak demand that's going to drive these binding periods, necessarily, going forward. In fact, when we model these things in our long-term studies, we actually model an hourly capacity reserve requirement in all hours of the year, because we don't know which hour it's going to be binding in. In order to get the right amount of installed capacity in the long-term for those conditions, and usually it's only two or three hours in the year when that constraint is binding, but it isn't necessarily the hour of peak demand. It's the hour of the net peak, and that's much harder to predict, and therefore harder to schedule the maintenance outages around and everything else. We definitely need outage scheduling rules but also market constructs that are going to reward market participants for getting that right, and not getting it wrong.

RESPONDENT 1: Ours was really net peak, minus forced outages. Because the forced outages are really where if you go from an 80,000-megawatt system, or really 75,000 is probably a better average and have 10% of those units on forced outage on any given day, or at least during the higher load days, you've got a big challenge there on how we solve for that.

NEXT HEPG PARTICIPANT: One question that is vital to the accreditation projects that some of the Northeast ISOs are undertaking: basically, how to provide a much better and accurate view of just what the capacity value is. It's a multiyear project, of course, for all three of the ISOs. But they're all getting there. But I think that would help a great deal.

I want to focus, though on transmission. The point was made that if they're not willing to make a really substantial increase in transmission, the benefit from the IRA would be very substantially reduced. And what it conjures up in my mind is the idea that without that transmission, you have a real twerking or distortion that you'd end up probably with suboptimal projects that would be way out of merit on their own without those subsidies, or that just make it into merit with those subsidies. But if only there were a broader, thicker transmission system, you would probably find that all those subsidies instead of going to projects that would be larger scale and really much better for society. It seems that transmission really looms as really fundamental here. And yet it bedevils a lot of dealing with markets, because by and large, transmission has been through a socialized payment mechanism that's out of market. And that's fine, because no one's figured out how to do transmission in markets.

And yet we on top of that, we have a serious NIMBY problem, and you know, the discussion was of a situation in Maine where companies poured money into that, because they wanted to protect their assets in New England. But at the same time, the environmental community has their own agency. They accepted that money, and they used it to defeat a project that would have brought 1,200 megawatts of green power down into New England. And I don't think the environmental community as a whole has ever really taken ownership of what they did to throw off the transition in New England for that action. And as you say, the courts may eventually overturn it. Right now, it's still stalled.

This takes me then to the question of, what as a practical matter, and this is a whole other conversation, needs to be thought through for what can be the level of improvement in transmission that can threat the needle of hopefully avoiding some of the NIMBY problems, but also addressing another point which we think about in economics, which is how far forward to do you plan a system? How much of risk of excess capacity is there vis-à-vis the economies of scale you achieve from a larger transmission system? And what is the cost benefit analysis of that? And we thought about this in terms of offshore wind. Do you think about a massive offshore project and a transmission system that could potentially connect 15- 20,000 megawatts of offshore wind through the Northeast? Or do we think about it as fleet number, smaller lines that are fit for purpose, but potentially suboptimal in a larger scale? Those are all the issues that we have to tease out here. But at the end of the day, it seems what is needed is a coherent view of serious to discrete transmission improvements that can be made and that must be made, or else we're going to end up really not being able to take advantage of the funds that are in the IRA that are really startling in their potential impact.

RESPONDENT 1: That's all really well said and I think you teed up the next thorny set of questions that we all have to focus on going forward. Getting the financial incentives in place is a necessary but insufficient condition. And so it's a huge piece of the puzzle that just clicked in. But it's not the whole shebang. And that's going to be, the next challenge is solving these critical challenges, particularly around transmission, but also other network infrastructure, CO_2 pipelines. If we really want carbon capture to play a meaningful role, so not everybody does, but if you do, we need a national CO_2 pipeline network. Right? Or at least large regional networks to emerge originally, and then potentially be linked into a national network, as we see in a lot of net zero kind of long-term studies. And so you have similar challenges there around EV charging networks, etc. Network infrastructure's going to be a critical overlay to all this, and certainly a thorny one that doesn't have a lot of easy solutions.

I do think that what we're highlighting here is that there's a national interest in transmission. It's shocking that we don't have any national regulatory authorities that are able to take that into account whereas we do for basically every other form of network infrastructure that is of national import. I'll just leave it there. There were put forth some interesting ideas about how to narrowly circumscribe what the federal role is here. But zero federal role is really quite bizarre when you think about it.

BILL HOGAN: So this is a follow up for our speaker about ramping products. In your presentation, you talked about an immediate and real problem that many regions share, and are certainly going to share as we get greater variability in supply. That's the ramping constraints. There are alternative ways to approach that. There seems to be almost a default assumption that we have to start inventing new products, product proliferation. So we'll be creating a ramping product and a reserve product and a contingency, and all these things come along. And another approach to this, which has been investigated in theory by the folks at ISO New England, So, you have a look ahead. You have to look ahead. The look ahead causes an estimate of what the impacts are going to be now and later, and so on. And if you look at that problem, and you say, suppose we had a rolling look ahead, then do we need to do anything other than just calculate the prices that would be naturally fallout of that, the locational marginal prices, and the answer in theory is, no. We're done. So, we don't have to specify a ramping product. Generators, loads, everybody could ramp to some degree, and they will see prices changing in a way, and dispatch conditions changing in a way that they make whatever capacity they have available. That provides the great advantage, then, that you don't have to go through all the regulatory stuff, like the last participant was describing for capacity as to how much does this ramping product really provide? And you just sidestep all those questions, because it falls out immediately in the prices. And I've my own view, obviously, that this rolling price thing is a very good idea that ought to be pursued more. But it seems to be the proliferation of products is the preferred strategy so far. I was wondering if we you could commend about that, without being a spokesperson for your entity.

RESPONDENT: In thinking back to how this came about, I think the, as you noted, the problem is real. Now, in terms of the solution, thinking back to when they started considering what to do, I think the desire was to do something that would not affect how the dispatch worked. And in SPP, it really is only one five-minute optimization. Other RTOs, California, New York, for instance, they do have a period, let's say an hour or so, where they're actually already doing this. They're just not using those results in any way currently. But SPP is not. And so their worry was, if they had to do something more elegant, that it would be, they were looking for a solution that they could use without doing something more aggressive in terms of the software change. So the desire there was to use the product. However, as I sort of noted in the presentation, is that unfortunately this shortcut approach misses some key issues, particularly how do the prices fall out of the solution, and where would you actually materialize this additional ramp? So is a kind of Achilles' heel, in my view. So, I think the attempt was to try something without having to overhaul the software. However, the stranded nature of what they're procuring kind of leads you towards the approach that you've been outlining just a moment here is this multi-period optimization. You're going to eliminate some of those. So I think that was essentially the cost benefit tradeoff that led us down this particular path.

BILL HOGAN: Thank you.

HEPG PARTICIPANT: I wanted to follow up on prior comments as well, because I think this is a very expert group in the policy of how things like transmission get built. And I suspect that there's a lot of skepticism on the Zoom, about the ability to actually build all the transmission that we're talking about. In particular, you know, the Princeton report and as was think pointed out at the last HEPG, the amount of land use across the country for what we're talking about from the IRA is really huge. The amount of transmission was double or triple the existing transmission architecture in the next 30 years. And we don't really have federal siting to get that done, as the speakers acknowledged.

And I wonder why there isn't more of a rethinking of the potential role of nuclear in this, and thinking about doing it differently. You know, the IRA did say, OK, we're going to have ZECs to allow all the existing nuclear plants to stay open. But there was nothing about what role nuclear might play going forward. And you know, as I alluded to at the last HEPG, it seems to be a strange system to have each state, each utility in each state choose to do one nuclear power plant facility and not benefit from any learning curve economics. I would imagine that it would make more sense to have two to four companies that own and operate all the nuclear power plants in the country, and yet we just don't have that as a mechanism. And so, we get situations, like we've seen, that are very unsupportive for having a robust nuclear industry. So I'm curious to see what comments people have on that and whether nuclear can be part of a solution here.

RESPONDENT 1: I think we need a set of what we call clean firm resources to meet the reliability needs affordably in a carbon-free system. And augment whether dependent variable renewables and energy constrained or time constrained resources like storage and demand flexibility. I think study after study shows that. That's if you have no constraints on transmission or land. If those are practical constraints, then the role for firm resources certainly increases. And that could be nuclear. Right? And it could be other firm resources as well. And I think we have a big, diverse country with a big, diverse set of resources available and a big, diverse set of social preferences. So my guess is we're going to need all of the clean firm options that are being developed in some parts of the country. And there may be some that need nuclear and others that don't. There are going to be some that can tap into advanced geothermal, but that's not going to work in a big chunk of the country. Etc., etc. I think we're going to need a really robust portfolio if we want to get the whole country there. And I think nuclear has a potential role to play. Of course, the industry has to realize its potential, in order to build projects on time and on budget and at a reasonable cost to play that role. And it's got to compete with everything else that's available in each region.

I'd say we have been actively exploring other ways to reduce transmission build out, because every time we look at our maps, we cringe and worry about our ability to execute on that. And, in addition to building more firm resources, when we constrain transmission, we do see a larger role for solar relative to wind, because solar has much greater siting flexibility and can be located much closer to load in general than wind. Because the resource potential for wind varies at the wind speed cubed. And the wind speeds vary at about a factor of two, which is about in parallel with the solar installation. So you get an 8X better site for twice the wind speed, whereas you just get 2X better at a solar site. And as we start to oversize solar anyway, on the DC side relative to the inverters, the variation you get in capacity factor starts to shrink across space. And so solar may be an option when we start to constrain. Compared to the Net Zero

America study, for example, which is what I think you were siting for land use and transmission build, we had about 50/50 wind and solar in the kind of least cost unconstrained scenario. When we run things under more realistic transmission constraints, it shifts to more like a third solar, or a third wind and two-thirds solar. The other way to reduce transmission build by maybe about a fifth is co-location of storage. And you see that all over the queue, as a way to reduce the amount of interconnection you need and increase the value of wind and solar projects. Princeton has a study being submitted for peer review as well that looks throughout the WAC. Our models typically in the past, assumed storage and wind and solar are not located at the same place. And we don't; we have a fixed ratio of the grid connection to the behind the substation resource size. When we let our model co-optimize all that, it tends to build a lot of solar and storage with not as much transmission, and then use the storage to make much better use of that transmission. We're seeing that in reality in the queue. That made us scratch our heads and worry our model was missing something. Indeed, when you would give the model the option to do what the market's doing, then it does what the market's doing. So it's good. People aren't crazy. The model was wrong. But there are ways to incrementally at least whittle down the role of transmission.

We can't get by without any large-scale transmission expansion. I guess the only thing that's given me some confidence is that we're not talking about an unprecedented rate of expansion. We're talking about the kind of rate that we had going over a multi-decadal period the last time demand was growing at about a steady 2% per year clip. We can physically do this. It's not an unprecedented scale, where some of these other deployment rates for solar and wind are unprecedented. But we did all that before restructuring. And so it is my concern that we have a correlation here between the period when demand started to flatten out, which you would expect to lead to slower transmission expansion, all else equal. So maybe that's all that's going on. But also that's when markets restructured. And so maybe it's an issue with how we've restructured the planning and regulation and siting responsibilities at the same time. And so, you know, open question, but at least it's not something that's totally out of the historic precedent to grow the grid at 2 to 2 ½% per year. We did it for three decades in a row.

RESPONDENT 2: Yeah, one thing that we've been looking at in Texas is, how do we be better stewards of our rights of way? How do we get more through the existing rights of way? Is that higher capacity conductors? Is it different technologies? We have a number of facilities around the state that were permitted for double circuit lines and originally constructed as single circuit. So we're actively looking for projects where we can add additional circuits and then higher voltages. I would say while we're not a massive geographic region, we still have a lot of losses when it comes from West Texas wind, Panhandle wind into our load centers. And if we can use some higher voltages and reduce losses within the same rights of way, we likely will be better off.

RESPONDENT #: Yeah, there's an interesting graph for our forecasting. We do a Monte Carlo simulation to figure out our resource needs, loss load probability out there. And we simulate loads over the last 50 weather years to look at different things. When I look at the graph, it's interesting, there's 15,000 megawatts on a flat line over 50 different weather years. I've got to have 15,000 megawatts, 365/24/7 a year. To your question earlier, that's where nuclear just fits in. It's just, it's going to be there 24/7. Though, as you go all the way up to about 45,000 megawatts, the system, especially when you get that 30 to 35,000 and above, there's a lot of froth up there, a lot of just bouncing around the load, a lot of volatility.

We talked earlier about a lot of supply side and expanded transmission out there. But to the extent we can actually reduce that volatility at the top, just take the froth off the top, somehow through the demand side, either distributed energy resources, which bring load down during those really volatile time periods, or just better thermal shelves out there to customers, we actually reduced the amount of generation we've got to meet. You reduce the amount of complexity around these intermittent resources out there that are great because they're free energy, and you don't have to have as much transmission. I wouldn't underestimate the demand component in this solution, too. Looking at plans into the late 2030s, nuclear starts coming back in as one of the options you're going to be looking at out there. So we definitely see it as part of the solution. But again, it's an all of the above. I think my colleague on the panel hit it really well in their comments. It's got to be an all of the above. There's no silver bullet to any of this problem out there. It's taken a lot of different solutions.

MODERATOR: I'm glad you brought up demand, because I think that is still one of the parts of the equations that we need to explore a lot more. But given the time limitation, I knew this was going to be a very rich conversation. But Bill, I'll give you the last word, which means that it probably cannot be a long question. You probably want to bring us to a closure around four o'clock. Thanks, Bill.

BILL HOGAN: So there's another policy debate that's going on about high drug prices in the United States, and controlling them and so on. And there is a view, which I hold, that high drug prices in the United States are a great thing because they're a massive subsidy to the rest of the world, particularly the developing countries, which then get really cheap resources that they can take advantage of, because of the investments that we have made. There's sort of an analogous question here about zero emissions and clean energy and all that kind of stuff, because you go to a developing country, they're not going to be able to afford the subsidies themselves. Are we going to produce in the later years, according to the Princeton study of reproducing technologies that would be appealing to developing countries that have an alternative, which is coal they might prefer or natural gas? Of course, that's the real problem here going forward, is this global story. So what the insight from your work about that projected cost improvements?

RESPONDENT: Yeah, it's a great question. It's actually one we're about to start a couple of studies focused on. I was just chatting with a collaborator over lunch about how we can help quantify that impact. It's a difficult one, of course, to project with any certainty what the impacts are. But there is a growing amount of literature that helps unpack the cost declines that we do see historically for a range of technologies as they scale up and deploy. Not just energy, but elsewhere. And try to classify a taxonomy of different characteristics that might help us understand how fast that experience curve is likely to go? What are some of the causal mechanisms that drive it over certain stages, because it's a correlation that is remarkably consistent, but the underlying causal mechanisms that drive it vary over time. And also, some of those elements are local. And some of them are global. Mass-manufactured commodity products like LEDs or solar PV are very likely to spill over into lower costs in the developing world. Custom manufactured or installed technologies like, say, rooftop solar installations or complicated nuclear power plants are not so likely to transfer. Right? You need local expertise embodied in the people who build those projects. Unless they're shipping them over to West Africa, they're not really going to make any difference there.

We're trying to unpack that, and trying to use those taxonomies to predict more what the combination of what the US, Europe with its efforts to get away from Russian oil and gas are doing now, and China with their huge investments in these sectors, is likely to do over the next decade or so to catalyze cost reductions for hydrogen, carbon capture, advanced geothermal, nuclear, etc., EVs, heat pumps. What we've seen is that this does work. We can make clean energy cheaper. Right? we've made LEDs 98% less costly over a decade. We've made lithium ion batteries and solar PV about 90% cheaper. We've made wind about 70% cheaper over a decade, through exactly the kind of thing you're talking about, which is wealthy countries spending public subsidies, and in some cases personal money for the voluntary action, to cover the cost when they're expensive and to make them cheaper for the rest of the world.

I do think absolutely the core goal is to make clean energy cheap in real terms, not just in subsidized terms, and we do that through innovation policy, and we do that through deployment. That deployment can be driven by a carbon tax, or it can be driven by deployment subsidies. We've taken the latter route here in the US, and Europe has more of a mixed bag, and China very different. But you know, we are seeing deployment at scale of the suite of technologies that we need, and that makes me a lot more optimistic that we're going to see the kinds of cost reductions that will make it easier for the rest of the world to take action and to follow us. I think that's so much more important than doing our part. Leadership is more than doing your part, in terms of zeroing out my own emissions, or the US is taking care of our own emissions. So much of the global conversation is focused on that. Leadership is making it easier for other people to follow, and that's exactly what driving down the cost of these technologies can do for the rest of the world. Very well posed question.

MODERATOR: Well, with the time running out, I just want to ask everyone to show a clap of hands for everyone on our panel and the great discussion we had today. Thank you everybody for participating. And we'll see you next time at the HEPG.