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BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the matter of,)
)
SB100 Joint Agency Report:)
Charting a path to a 100%)
Clean Energy Future)

SB100 TECHNOLOGIES & SCENARIOS WORKSHOP

CALIFORNIA PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CALIFORNIA 94102

MONDAY, NOVEMBER 18, 2019

9:30 A.M.

Reported By:
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J. Andrew McAllister, Commissioner, California Energy Commission

Liane Randolph, Commissioner, California Public Utilities Commission

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Presenters & Panelists Present

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P R O C E E D I N G S

NOVEMBER 18, 2019 9:30 A.M.

MS. GUTERREZ: Good morning. If everybody can just take their seats, we'll go ahead and get started. Okay, welcome to our SB100 Technologies and Scenarios Workshop. My name is Alicia Guterrez. I'm with the California Energy Commission.

Today is an exciting workshop. A full day of activity and information coming from stakeholders and experts that are all looking ahead to the clean energy future of a hundred percent renewables.

So, we will have some panels on scenarios today, looking at key trends and outlooks to 2045. We're also going to be looking at the resource mixes for modeling work that we'll be doing for SB100 and assessing those resource mixes along the way.

ARB will present some proposals on how we define zero-carbon resources. We will present modeling assumptions and new analyses.

And then, we'll have an afternoon session looking at renewable and zero-carbon enabling non-generation technologies that are key to implementing SB100.

So, this morning we will kick our workshop off with opening comments from Commissioner Andrew

McAllister, and our principal for SB100, Commissioner Liane Randolph from the CPUC.

We will also queue up Chair Hochschild once he arrives, for his opening comments.

Go ahead. Thank you.

COMMISSIONER RANDOLPH: Good morning everyone, thank you for coming to this technical workshop. As some of you have participated in over the last few months, we've had scoping workshops around the state in Fresno, Redding, and Diamond Bar about the SB100 report. And we've heard a lot of perspectives from a lot of different stakeholders about equity issues, land use issues, reliability, affordability, and, so, we have appreciated listening to all of that perspective.

Today's workshop is going to be a technical workshop where we start to look at key technology trends and outlooks that will help us achieve the SB100 goals.

To my mind, one of the benefits of the SB100 report, it gives us an opportunity to not only see where we are in terms of gauging our progress, but also helps us identify what technology opportunities are out there, and help us think about planning to that SB100 goal.

So, I appreciate everyone's participation. I'm going to apologize in advance, I ran into a conflict this morning that came up, after we scheduled this. So, I'm going to duck out for a little bit. Hopefully, just for the morning and be back in the late morning and for the afternoon session, if all goes well.

So, thanks for participating and I will turn it over to Commissioner McAllister.

COMMISSIONER MCALLISTER: Thank you, Commissioner Randolph. Well, thanks for hosting here, hosting us at the CPUC. We really appreciate the partnership. And also, ARB today presenting. I think it further emblematic of just how closely we're working together across agencies on SB100, as required by statute but, really, just as required by common sense and good policy. So, really happy to be here.

And, certainly, the ground rules, and the definitions, and the modeling tools, and the assumptions all really matter for getting SB100 right over time. And so, we're still -- you know, we're really in the early phases, defining the landscape under which, you know, on which we're going to operate over the next couple decades, getting us where we need to go.

So, this is, as Commissioner Randolph said, a technical workshop. And so, this is where the sleeves start to get rolled up and we really start focusing and understanding on focusing on the pieces that need to fit together well in the real world to maintain a reliable system that moves us inexorably towards clean energy.

So, I think I've said it at every workshop, but it seems to sort of keep the focus on the right things. That this is not just RPS on steroids, right, this is -- this is not just RPS on steroids, I'll say it again. It's really a system reliability planning exercise in a context of deep clean energy. And so, I really think the tools and -- I mean, reliability has to be job one. You know, we're talking about resilience, and fires, and building the system that we need in the future, and so, all these challenges have to come together in a way that maintains and enhances reliability.

And so, I personally am really looking forward not only to the morning and the modeling questions, but also the afternoon where the technology, the non -- you know, distributed technologies and different forms of generation, certainly, but also non-generation options and non-wires options are going to help us reach our goal for decarbonization. And so, I think that's got to be a core piece of the solution.

And, you know, personally, I think that it's relatively under baked, and so that's a place where we really have to make a lot of strides, and figure out how the system's going to work and be resilient at the local levels, at the distribution system level.

So, I think that's -- I'm looking forward to that today. So, with that, I'll wrap up and pass it back to Aleecia.

Thanks everyone for coming. I think it's going to be a really exciting day, so thank you.

MS. GUTERREZ: Thank you, Commissioners.

So, now, we will turn it over to Siva Gunda, who will be presenting on our SB100 Joint Agency Report Overview.

MR. GUNDA: Good morning everyone. Thank you again for joining us for the first SB100 technical workshop. I'm Siva Gunda. I'm the Deputy Director for the Energy Assessments Division at the California Energy Commission.

So, I would like to go through the overview of the report process and what we're hoping to do, and some of the timelines.

Thank you. As most of you are aware, the SB100 bill not only calls for a 60 percent RPS by 2030, but also sets that it's the policy of the state that eligible renewable resources and zero-carbon resources supply 100 percent of all retail sales of electricity to Californians by December 31st, 2045.

The bill also requires that the achievement of this policy does not increase the emissions in the

Western Grid and, also, does not allow for resource shuffling.

The bill furthermore requires a Joint Agency Report for the Legislature in a periodic fashion.

The planning for the Joint Agency Report started in earnestness earlier this year with the formation of the Interagency Principals Group that includes Chair Hochschild, from CEC, Commissioner Randolph from CPUC, and Chair Nichols from CARB. The group, the principals, the SB100 principals are the high level leadership for the interagency group to provide both guidance, as well as a structure and process.

Below that, below the principals we've created an interagency staff, a collaborative process and structure, and that allows for regular contact with each other and discuss, and move forward on developing the report.

Obviously, an important part of this report development process is the engagement with the stakeholders. So, as you see in the chart here that's highlighted through the workshops, and the docket that we've developed, we want to ensure that the stakeholder input is well heard and fostered through the process.

Another important element that the SB100 bill calls for is the engagement with the balancing authorities. To that end, we've developed a Balancing Authorities Working Group. We've had a kickoff meeting just before we did our scoping workshops, and we are going to engage with them periodically, specifically on the reliability issues.

Some of the --

(Technical difficulties)

MR. GUNDA: Okay. All right. So, the interagency collaboration process, one of the key things is each of our agencies has a very different perspective based on our statutory requirements. And the interagency coordination allows for a robust discussion of these various points of view.

So, just kind of highlighting the language from the Joint Agency report, the bill basically calls for in consultation with the California balancing authorities, through a public process issue a Joint Agency report by January 1st, 2021. That's only about 14 months away at this point. And at least every four years after that.

And it specifically includes language on developing technical review of the policy, potential benefits and impacts on system and local reliability, nature of anticipate financial costs and benefits to utilities, barriers and benefits of achieving the policy. And, most importantly, also developing and looking at alternate scenarios to achieve the policy.

So, based on some early guidance that we've received from the SB100 principals, we've laid out four principle goals as we embark on developing the report. So, the first one is to ensure that the statutory requirements of the report are actually met. And this, we hope, is done through having a robust public process.

So, as we develop our interim steps and talk to the public in these workshops, we hope to receive ample feedback and ensure that the statutory requirements are well honored in the spirit of the bill.

The second thing is to provide direction to the electricity market. This is to make sure, since we're looking at a 25 to 30 year plan, ensuring that the market as clear direction as we embark on the SB100 process.

This, for example, can be done through clearly articulating what technologies or what generation technologies would be considered as zero-carbon resources and laying out the attributes that are potentially qualifiable for this process early on in the process.

Third is to coordinate a planning process of state agencies. As most of you know, each of the agencies, even the three of us in the room here, the

CEC, CPUC and the CARB, we have a lot of modeling work that we all do for our own statutory requirements, and this is an opportunity for all of us to align some of the common assumptions to the point we can, and then adopt common tools and assumptions to the extent possible. So, the modeling that we do for SB100, but also the various other paradigms, such as the IEPR, the IRP, and the Scoping Plan all have some way of aligning around the electricity sector.

And, finally, form consensus on interpretation of the statute. This is kind of going back to the earlier point about the zero-carbon resources, what exactly does that mean?

So, my colleague, Chris, the next presentation, is going to lay out some of the modeling assumptions, and then kind of our view. My colleague from CARB is going to talk about our preliminary interpretation of what zero-carbon resources could be as we think about modeling.

Liz, can you give me a hand? So, as we do this, some of the key considerations we have to think about, some of these are explicitly called out in the bill and some of them are not, is to look at the reliability. What exactly on the 2045 grid, supporting a zero-carbon, 100 percent zero-carbon resources really look like, and what the potential reliability issues?

An important aspect that Commissioner Randolph mentioned in her opening comments, that we heard over and over, is really the energy equity. How do we make the solutions that we pursue and kind of lay out in SB100 are equitable, in the sense that it provides all Californians the same opportunities?

Finally, think about innovation and emerging technologies. We're going to talk about this extensively this afternoon, looking at some of the emerging technologies and how do we think about the zero-carbon resources.

Other aspects are affordability. This is something that we are not going to be able to quantify very well in the first report. To the extent the modeling will reveal the total system costs, and that's something we're going to discuss in the report. But the actual rate impact is something that we have to continue thinking about as we move forward.

Another thing is the resource diversity and flexibility. To the extent how does the whole western interconnect, and the resource flexibility and diversity affect the SB100 goals.

I'm just going to lay out, at a high level, the workshop topics we've conducted since September 5th at our kickoff workshop in Sacramento, followed by three workshops on scoping. So, basically, we laid out what we’re thinking and heard from stakeholders, their perspectives on equity, reliability, and such. And we were able to take adequate notes on that and hope to really integrate that, as we move forward into our modeling.

Moving forward, though, apart from the scenarios and technologies workshop today, we’re looking at some of these key topics for specific workshops, which is electricity system modeling. As Commissioner McAllister mentioned, the SB100 report is really about a comprehensive system modeling and ensuring that the system modeling that we do clearly lays out the reliability issues and the resiliency issues as we move towards the SB100 goals 2045.

Affordability is another topic we are hoping to have a workshop around. We’ve touched upon equity a lot during our scoping workshops, but that’s something, based upon the amount of interest and the importance of that, we hope to touch on in a workshop on that.

The other one, with the balancing authorities, is to talk about the reliability needs. So, we’re hoping to have one workshop specifically discussing the reliability system resiliency.

Just to kind of touch upon and tee up the conversation for the rest of the day, the work, the report itself, we look at it as two specific parts. There's going to be a quantitative element through modeling that we hope to achieve in the next six months or so. But a lot of topics that we laid out will be touched upon qualitatively for the very first report.

For example, on the quantitative side, our hope is to really build upon the IRP modeling. CPUC has done really good work and extensive work on the 2045 scenarios, just for the jurisdictional, which we hope to expand to the California statewide modeling effort. So, that's something Chris is going to talk about in a few minutes.

As discussed, the modeling that CPUC has done previously, and which we are going to do, will evaluate some of the costs and benefits from a system cost perspective, but the rates will not be a part of that discussion.

So, even though we will be touching upon quantitatively slighted on some of the topics to your right, which are under the qualitative side, most of those topics will be qualitative.

For example, today's discussion this afternoon will kind of set up a record on the technology trends.

And some of the key assumptions are the costs moving forward and what kind of Technology's qualified for this. This will be a continual record, year after year, as we move forward. So, with each year there will be a qualitative aspect, but some of that will be translated quantitatively into the assumptions.

The system benefits reliability is something we do not expect to delve into very deeply for the very first report. But with our working group, with the balancing authorities, we hope to develop a solid framework on how to pursue this moving forward.

On the energy equity and affordability, as I said we're going to have the total cost, but not necessarily the rates, and that's something we'll be looking into as we move forward.

Environmental implications is something we cannot stray away as we do the SB100 work, so that's something we will be qualitatively touching upon. But as we move forward and start kind of coordinating with other agencies, not just the three that are mentioned today, we'll look into how to tee them up, tie them up into our broader analysis.

Finally, looking at the interactions with other sectors, basically, how does electricity sector become a backbone for decarbonizing other sectors potentially would be addressed moving forward, but qualitatively discussed in this report.

Just providing a timeline, just backwards, January 1, 2021 is the report due to the Legislature. That's something we'll be working backwards from. Early summer is when we hope to have the draft report available for comment. We have three agencies and a broad public process, so we expect at least six months for the review process, and also have a couple of workshops both providing the preliminary results, as well as the final drafts.

By spring, we hope to finish most of our workshops that will kind of go into our draft report.

From an engagement stand point, we thank you again for being here today and we really hope you provide your comments through the docket, as well as verbally today.

To that end, we have an SB100 website, a dedicated website that's hosted at CEC. That provides up to date information on the events, links, and also there's an opportunity there to subscribe to the Listserv and submit comments.

So, with that, thank you.

MS. GUTERREZ: Thank you Siva. Also, I'd like to ask everyone, on your way out, if you wouldn't mind signing in with our Public Adviser. They're keeping a record of attendees in the room and can also get you connected with the Listserv.

So, next on the agenda we're going to hear about options for defining eligible electricity resources under SB100, from Ryan Schauland, from the California Air Resources Board.

MR. SCHAULAND: All right, good morning everybody. I'm Ryan Schauland, with CARB. Thanks Commissioner, thanks CEC, and thanks to CPUC for hosting today. I am the Manager of the Emissions Data Quality Assurance Section at CARB. So, I got involved in this work because my group oversees the reporting and verification of the data that gets reported under the mandatory reporting for greenhouse gas emissions. So, that's the data that gets used for the state greenhouse gas inventory, as well as the Cap and Trade program. And a lot of my background in that work, prior to me being a manager, was dealing with accounting issues related to imported electricity, so that's where I'm coming from.

So, today, I'm going to discuss some options for defining eligible electricity resources under SB100. So, as we begin modeling what the electricity grid's going to look like in 2045, one fundamental question will be what resources types will be considered as eligible to meet the goals of SB100. So, the focus of this presentation is to provide a starting point for discussions of what resource types we would consider when modeling the electricity grid.

So, Christopher, in the next presentation is going to talk a little bit more in depth about what that modeling actually looks like. So, this presentation is just going to focus on kind of the parameters of what resource types we would consider when doing that modeling.

All right, is this working or do I have to give you a cue to change slides? All right, perfect. So, you saw a similar slide in Siva’s presentation, the language in SB100. We’re going to return -- I’m returning to this to emphasize some of the particulars that you see underlined there. In particular, eligible renewable resources and zero-carbon resources. Those underlined sections are what I’m going to talk about in this presentation. Specifically, what’s eligible under the Renewables Portfolio Standard now, and what additional resources might be considered as either RPS eligible or zero-carbon under that language you see from SB100.

So, first, I want to present some of the questions that CARB, CEC and CPUC staff considered when discussing what resources might qualify as RPS eligible or zero-carbon under SB100. So, first, what counts as eligible renewable energy resources under RPS today and then, what could count as zero-carbon resources under SB100. It's going to have those two parts of it, what's eligible renewable and zero-carbon are both considered under SB100.

And then, when we consider RPS eligible and zero-carbon resources together under the same policy framework, like we would have to do for meeting the goals of SB100, do we find any inconsistencies that we're going to have to resolve in kind of combining those two regulatory frameworks.

So, today, we're really asking for feedback on two resource scenarios that I'm going to present in the next couple of slides. And your input's going to be really important as we model the future electricity system and the results of that modeling will then inform how SB100 is ultimately implemented. And we encourage you, of course, to submit comments to the docket.

So, the first scenario we're teeing up we're just calling, to give a snappy title, RPS Plus. So, this would include all the resources that are currently eligible under the renewables portfolio standard. So, this includes ones that you're familiar with. So, the emissions free resources, like wind, solar, and small hydro. It also includes geothermal resources and electricity generated from biological source fuels and feedstocks, so biomass and exempt biomethane.

And then, the plus of RPS Plus is that extra layer of what could be considered or are currently considered to have zero emissions under the state greenhouse gas inventory. So, that includes large hydro. It includes nuclear generation. And it includes nature gas generation where a hundred percent of a power plant's greenhouse gas emissions are captured and geologically sequestered.

So, for this option, we wouldn't propose any time restrictions on contracts. So, new large hydro, new nuclear, for instance, could potentially qualify.

And for carbon capture and sequestration, CCS, we would propose natural gas is the only fossil fuel option to be paired with CCS. And then, that would really allow natural gas power plants to provide that backup and grid balancing role, while the capture of all the greenhouse gas emissions with geological sequestration ensure that the electricity results in zero carbon emissions to the atmosphere.

Important to note on that one, the way we're currently considering this resource scenario is even with CCS we wouldn't propose to allow coal. And that's really because coal plants, you know, for the most part operate as base load generation. They're not good candidates for grid balancing and they don't currently play that role in our electricity system. And also, California, as all of you know, has worked for quite a while to move away from coal as a generation resource and we really don't want to backtrack on that progress under SB100, even with CCS considered.

And this scenario, RPS Plus, combining eligible renewable resources, as recognized under RPS, and what's considered zero emission under the state greenhouse gas inventory, that really closely aligns with those two frameworks we have now, RPS and the state GHG inventory.

Scenario two, similar to scenario one but it does not allow any resources that combust fuel. And so, this option we include here to really recognize that one of SB100's goals is to reduce air pollution. We know that, you know, in a future where SB100 goals are met, you know, we're going to have far fewer resources that are combusting, combusting fossil fuels, but they're still an impact to communities and to air pollution in general to have those sited somewhere. So, this scenario really wouldn't allow for combustion of biofuels. It wouldn't allow for combustion of natural gas, even combined with CCS.

And this, so some important things to keep in mind with this scenario is that it would limit the ability of certain RPS resources, potentially, to use fossil fuels during startup. It also would allow for electricity made from reformation, from biomethane. So, if you made hydrogen from reformation or from natural gas reformation and paired that with CCS that would be allowed because we wouldn't consider that as combustion. But any reformation were combustion was involved, for instance, to produce the steam that was used in steam methane reformation that wouldn't be allowed.

So, the previous two slides I discussed what might be considered as eligible renewable or zero-carbon resources under SB100 modeling. On this one we talk about a couple considerations for how that electricity's accounted for. There's going to be a lot of accounting considerations for SB100 going forward. So, these are just a few in terms of how they feed into the modeling of what resources are considered eligible.

So, the main accounting methodologies that we think are instructive to SB100 right now are the RPS program and the regulation for the mandatory reporting of greenhouse gas emissions, or MRR. That's the basis for the state's greenhouse gas emissions inventory.

So, those two programs are really complementary in their goals, obviously, to reduce greenhouse gas emissions in the state. But their treatment of certain types of electricity is a little bit different. So, including the treatment of Renewable Electricity Certificates, or RECs, is one key difference.

So, an example of this difference is for firmed and shaped power. So, under Portfolio Content Category 2 of the RPS program, RPS entities can essentially pair a REC with power that's imported to the state, in a kind of firmed and shaped arrangement.

Under the MRR, however, that firmed and shaped power is imported to California. It's considered to be from an unspecified source, so it's a source where we don't -- we can't necessarily tie that electricity back to its origin. And so, then it has -- under the MRR, it has the emissions of resources that operate on the margin. So, that incremental megawatt hour, we kind of model where that electricity comes from and give it an emission's profile from that. Right now, it's .428 metric tons of CO2E per megawatt hour.

And so, that same electricity really would be treated slightly differently under MRR and under RPS Portfolio Content Category 2. So, that's just one example of a potential difference between those.

Lastly, we want to flag electricity storage as a potential counting consideration. Storage isn't explicitly considered as a resource under either counting scheme, but it may need to be under SB100. To be compliant with the requirements of SB100, the energy used to create the stored energy would itself need to be either renewable or zero-carbon. And if that energy's ultimately used to produce electricity for the grid, that might turn out to be really straight forward as we get into it. But the more we were thinking about, the more potential kind of arrangements we could see that being confusing where hydrogen's potentially used as a source of electricity, but it could also be used as a transportation fuel source. SB100 regulates electricity to end users. So, those sorts of considerations we would have to deal with as storage becomes a bigger and bigger part of the grid moving forward.

So, again, we're asking for your feedback on these two modeling scenarios and, you know, those accounting considerations that I teed up. And again, you can submit your comments to the docket that was listed on Siva's slides earlier. That was 19-SB100. And that's it, thank you.

COMMISSIONER MCALLISTER: Can we ask a couple questions here? I just want to butt in.

MR. SCHAULAND: Sure.

COMMISSIONER MCALLISTER: So, that's for that. Really, really good stuff. And I have two questions, actually. Also, want to give the opportunity for the Chair to say some comments, as well.

I guess one has to do -- well, so maybe back up to the previous slide.

MR. SCHAULAND: Sure. I think I'll need some help from the -- okay, thanks.

COMMISSIONER MCALLISTER: But I guess one question is just how -- you know, I think as the EIM takes on kind of more energy and more -- it's not just sort of like cheap renewables, extra renewables sloshing around. You know, it's actually becoming a market in and of itself and there's going to be a day ahead.

MR. SCHAULAND: Sure.

COMMISSIONER MCALLISTER: I guess, how much progress are you making sort of unpacking the unspecified issue or energy to actually be able to sort of track back, working with the ISO to kind of track back and try to do that accounting in a more attributable way by resource?

MR. SCHAULAND: Yeah, thanks, that's a great question. Because we have -- as you mentioned, EIM keeps expanding to new entities and the conversation now is with the extended day ahead market, so we do expect that playing a bigger role.

We have a lot of ongoing conversations with the ISO on how to model that. It is a challenge, especially given both the MRR, the Cap & Trade Program, and SB100's requirement not to incentivize resource shuffling. And, you know, the secondary power generation that essentially fills in the gaps for that electricity that comes into California, making sure that gets accounted for, it's been a challenge, frankly. And I think it's well within the -- I think we'll get there.

COMMISSIONER MCALLISTER: Yeah, it seems like that's a solvable question given all the information that the ISO's collecting about those resources when they get bid in. And it will have more so in the day ahead. So, hopefully, that can get worked out. And, obviously, the Energy Commission and the Air Resources Board need to be on the same page about how we do that accounting.

MR. SCHAULAND: Yeah, for sure.

COMMISSIONER MCALLISTER: So, I know you guys are working on that.

And then, the second thing, do you see any -- all the accounting issues you talked about, do you see any that are kind of fundamentally challenging, or do you see them just sort of we have to decide on the ground rules and go from there? Do you see any that are really sort of sticky in the way that there's not a clear solution?

MR. SCHAULAND: I think the one that I highlighted with regard to PCC-2, how we deal with RECs in the program and how we account for directly delivered power to California that's potentially one because that's a place where, you know, given the mandatory reporting program's framework where we don't attach an emissions value to renewable energy certificates --

COMMISSIONER MCALLISTER: Uh-hum.

MR. SCHAULAND: -- and there's a lot of good reasons for that, you know, and background, too. You know, how the regulation is put together and that it's a statewide program, and there's, you know, restrictions on how we treat resources inside and outside of the state, and we're trying to be really consistent with how we do that.

And so, that's, I think the fundamental one that we've kind of been kicking around. But in conversations we've already had with CEC staff, I think everyone seems eager and willing to bring that to ground.

COMMISSIONER MCALLISTER: Yeah, great. Okay, well, thanks for the presentation. And, luckily, we live in a world where we have lots of good options for solving these options. And I think, you know, giving credit where credit is due, we should do all we can to make sure that the right renewables get the right credit. So, I know we're all working hard on that. So, anyway, feedback from stakeholders is really needed to help us with that.

MR. SCHAULAND: Okay.

COMMISSIONER MCALLISTER: So, we're lucky to be joined by Chair Hochschild. So, you want to make some opening comments of your own. Yeah, put you on the spot.

CHAIR HOCHSCHILD: Good morning everyone. Thanks for being here. And just, I'm sure, ditto whatever you said in your welcome remarks.

The only thing I'd point out, just the pace of innovation that's happening now in clean energy, and in storage is remarkable. I spent much of last week visiting some energy storage companies, including one here in Richmond that we funded through our CalSEED program. And I just think it's worth remembering that the universe of available technologies to help us reach these goals is expending in real time, and as the cost is declining. And we all know, you know, lithium ions, you know, a large role in that, and the cost reduction going from $1,000 a kilowatt in 2019 to $120 today, and falling. And that is certainly a trend that's to all of our advantage. But there's a lot of other chemistries and a lot of other improvements still to come.

But thanks for everyone, and special thanks to staff for all the hard work pulling this together.

MS. GUTERREZ: Thank you, Chair.

Okay, and we will be hearing about some of those emerging technologies this afternoon.

So, next, we will have a presentation from Chris McLean of the California Energy Commission, presenting on some of the analysis we are planning under SB100.

MR. MCLEAN: Good morning all. Christopher McLean, California Energy Commission staff. I'm in Siva's division. And as Siva laid out, the SB100 report sets forth certain requirements about the analysis that we intend to do.

This morning, I'll briefly cover, at a high level our sort of guiding modeling assumptions and then touch a little bit further in detail on the planned SB100 analysis Siva laid out.

We've got a fair bit of work to do in about six months. And in order to incorporate this analysis into the report rightly, I think the bulk of the modeling effort is going to come in the first half of this six-month push. Luckily, we're surrounded with good teammates in the other agencies and we're optimistic about getting that done.

All that, to set up an invitation to stakeholders that if there's something you see here missing today, please comment early and often. I think, as I'll discuss a bit later, there are plenty of opportunities to possibly shape the analytical effort that we have before us and I think input from the stakeholder group will be key to doing that.

So, Siva had a slide like, similar to this as well. So, ultimately, to get at this SB100 solution, we've got to work hard to identify resource portfolios that meet both our renewable energy and climate targets.

The PUC, in their IRP proceeding, is doing some very good work. And the focus in that proceeding has rightly been narrowed to cover PUC jurisdictional and CAISO footprint situated entities. I think it's on -- the Energy Commission recognizes that, you know, we need to do the work to extend that analysis and cover the statewide perspective.

All of these modeling efforts serve to establish a basis for assessing the costs and benefits, as well as impact. And again, extending this to the statewide effort is going to be a bit of work, but I think we're in good company. So, again, we would appeal to stakeholders to point out places where we can leverage opportunities for a feedback loop. We would very much like the stakeholder community to point out areas where the qualitative analysis may be able to inform our quantitative. And as we go through the modeling efforts and come up with results from these simulations, we would similarly hope that there's a feedback loop from the quantitative side into the qualitative.

So, Siva laid out some key considerations. And if you think about each of these as to whether they fall into qualitative versus quantitative bucket, I've highlighted in green the sorts of considerations that can find themselves relatively more readily modeled in our traditional simulation approaches.

So, the resource diversity bubble there, and flexibility, those ones tend to be a product of the sort of portfolio selection process. So, to the extent we're able to take hints from the innovation and emerging technologies bubble, and incorporate that into the space that's available for tools like RESOLVE or other capacity expansion models to select and represent these resources as solutions, we very much want to do that.

The reliability question, so here we're treating the two components of reliability, adequacy and security. The adequacy pieces, arguably, a little bit easier to land in the sorts of modeling efforts that we have contemplated near term. I think the security and operations questions, I think we look forward to engaging much more deeply with the balancing authority community.

With respect to the environmental impacts, I think there's good work being done at the Commission, already. Our colleagues in the siting division, if you've been tracking the IRP proceeding, Scott Flint and a team at the CEC is facilitating the portfolio mapping process by which the outputs of the PUC's IRP reference system plan are mapped and set to a bus bar basis that facilitates modeling in the California ISO's transmission planning process.

So, that mapping effort I think is opening up to stakeholders a bit more broadly than it has previously. I think we're finding good engagement from stakeholders on that, with requests for looking at things in different ways, opening up the transparency. And, ultimately, ending with a tool that Scott Flint and his team are working on that will facilitate ready stakeholder engagement with a took that goes a long way towards, you know, answering and performing these portfolio mapping exercises.

So, as we've heard mentioned from the Commissioners, we're at the very early phases of this process and we're looking to stakeholders, again, for any input that you might have to help inform this modeling effort.

The key set of assumptions will most likely stem from existing studies. And so, the CEC has -- if you're familiar with the Deep Decarbonization Report, this work was a pathways modeling effort that has yielded three particular scenarios that the CPUC IRP process has picked up and adopted. Those formed the core of the SB100 2045 framing study.

We expect that maintaining this consistent set of input data and underlying assumptions wherever possible will result in a more consistent modeling product and allow for comparison of the statewide modeling effort that we undertake with the work that's been done in the PUC IRP proceeding.

So, while we may end up with, to the extent possible, similar assumptions and input scenarios, we want to understand differences that may be required when we get to the point of implementing a statewide versus the jurisdictional and CAISO constrained sort of portfolios.

Another area that we expect to inform our collection of data inputs and modeling scenarios will be the work that the POU community has done in many of their Integrated Resource Planning reports. Those efforts have been well received at the Energy Commission. And having reviewed or been familiar with the results of those efforts, I think the Energy Commission staff looks highly upon those efforts that were made. It’s good quality work and I think we need to take care and capture the value from this POU perspective.

There are also other reports, and I think we’ll hear more, later today about the LA100 study. So, there’s a few of these studies out there that will serve us well and we expect to lean heavily, anywhere we can, on these additional studies and reports.

So, given the constraining assumptions of the Deep Decarbonization report and the SB100 2045 Framing Studies, I think I’ve alluded to it thus far, the ultimate goal is extending to the statewide perspective. And so, the details of how that has to be done are technical to be sure.

We’re currently in the midst of scoping discussions with our project consultant. And, ultimately, what has to happen to extent this effectively and comport with the 2045 Framing Study is that we've got to expand this RESOLVE model to cover additional balancing authorities. So, we intend to incorporate representation by the LADWP, Banc and TID, as well.

So, the place where, again, we'd like to highlight, so the core scenarios of the high electrification, high biofuels, and high hydrogen will definitely be the feature result set.

But I think there's a lot to be gained from considering additional sensitivities. And this is where, you know, I think we've heard from Commissioners and policy leaders that entertaining variations and sensitivities on these three scenarios that perhaps look at tradeoffs between, say, something like offshore wind versus out-of-state wind, or looking at a sensitivity whereby we need to come up with a replacement for the natural gas thermal fleet.

So, to the extent that others of you, in the stakeholder community, have scenarios that are of particular interest, we're eager to hear about what those are so that we can, early on here, incorporate those into our analyses.

So, there are, you know, really two core efforts. First, the extension in the RESOLVE modeling space. And the second is an effort to further align or make an assessment of the alignment between the demand projection that comes out of the PATHWAYS model in the deep decarbonization work, versus the California Energy Commission's Demand Forecast.

So, both of these models are of a bottom up nature and so it can be difficult to say sort of which policies are affecting the forecast versus the PATHWAYS projection. And both of the models are quite complex, as well.

So, the second objective is to, you know, end up with a pretty comprehensive understanding of how this PATHWAYS projection and the demand forecast coming out of the Energy Commission, how are they alike? What similar things are driving them? And contemplate the implications relative to each of the sort of three scenarios out of the deep D carb work.

So, at the outset, you know, I alluded to the timeline. It may be a bit aggressive, but I think with the support from the other agencies and lining out, you know, the scope of the technical agreement with the project consultant we should be in good shape to initiate and complete the planned analysis and the modeling exercise, having obtained RESOLVE outputs at some point near the end of the first quarter of 2020.

And then, in the second quarter integrate that all into the report framework and give a chance for all to review the draft effort. So, again, stakeholder input, we definitely want to hear from you. The means to do so, Siva covered that in his slides, but I'll leave it again here. And we look forward to your comments.

MS. GUTERREZ: Okay. For this next section, you're going to be hearing about some of the existing directional studies that are providing some guidance as we look towards the SB100 targets.

We'll hear from Jason Ortego, first, from the CPUS. And if you can -- if all the speakers for this section could just come to the tables here, and then we will pass it quicker around.

So, we've got Jason Ortego from the CPUC, Arne Olsen from E3, James Barner from LADWP, and Erica Bowman from Southern California Edison.

MR. ORTEGO: Good morning. I'm Jason Ortego, Advisor in Commissioner Randolph's office, and I'll be presenting the results of the CPUC IRP's SB100 Framing Study Scenarios. This is a study that I worked on with the IRP team and with E3 earlier this year, when I was in the Energy Division.

So, I'll start with a brief overview of the IRP at the CPUC. The value proposition of IRP is to reduce the cost of reducing GHG emissions and achieving other policy goals by looking across individual LSE boundaries, and resource types, and finding solutions that might not otherwise be found at the LSE level.

The goal of this cycle is to, like the goal of the previous cycle, to ensure that the electric sector is on track to help California achieve its GHG reduction goals. And also, with this study to explore how achieving SB100 could inform IRP planning in the 2030 time frame.

California today is a complex landscape for resource planning and IRP. We have multiple LSEs, including utilities, ESPs, and a growing number of CCAs, and multiple state agencies are involved in IRP.

CEC provides the IEPR Demand Forecast that flows into resource planning at the CPUC. ARB established the GHG planning targets for IRP. And the portfolios that the CPUC IRP team develops end up flowing into CAISO’s transmission planning process.

So, a 2018 Commission decision established IRP as a two-year planning cycle. Year one is focused on generating and evaluating an optimal portfolio at the CAISO system level, using a capacity expansion model called RESOLVE, and a production cost model called SERVM and Parallel. It's focused on adopting a single portfolio as the reference system portfolio to be used in statewide planning, including the CAISO TPP.

The first year it develops filing requirements for LSEs to submit their individual IRPs. And there are actions identified to implement the selected portfolio, the reference system portfolio, such as new procurement authorization.

So, you can see the red circle is where we are now. There was a ruling issuing a proposed reference system portfolio a few weeks ago, and we expect a Commission decision on that portfolio early next year.

Year two is focused on the LSE development of individual IRPs, expected to be filed May 1, 2020, staff evaluation of those IRPs, both individually and in aggregate, and then the proposed adoption of a preferred system portfolio to be used in statewide planning, as well as actions to implement that portfolio.

The purpose of the 2045 Framing Study was broadly to explore how the 2045 goal may affect resource planning in the electric sector in the 2030 time frame, while considering the economy wide picture and interactions between sectors, such as the electric and the transportation sector. And, also, to inform Commission decision making around what should be the appropriate 2030 GHG emissions target and optimal portfolio of resources in IRP to meet that target.

And these results were intended to provide directional information to the Commission, to stakeholders regarding the least cost, or least regrets investments needed by 2030.

The idea of looking past 2030 is that some near term investment decisions may actually depend on changes that occur post 2030.

So, three scenarios were explored to reflect different decarbonization strategies across the state. We have high electrification, high biofuels and high hydrogen. These three scenarios were selected from the 2018 CEC Deep Decarbonization Report. And they each satisfy California's economy wide goal of 80 percent below 1990 levels by 2050.

The electric sector GHG emissions target and electricity loads vary by each of these scenarios and are a product of complex cross-sectoral interactions within each scenario.

Electric sector GHG emissions and electric loads by sector are outputs of E3's PATHWAYS model, which was also used to develop CARB's Scoping Plan update in 2017.

This slide shows final energy demand by fuel statement for each of the three scenarios studied. On the left, you can see how energy demand by fuel type changes over time in the high electrification scenario, out to 2045 or 2050. On the right, you can see a side-by-side comparison of the scenarios in 2045.

So, note a few key differences are that in the high biofuels scenario, which you can see in the middle, it's more dependent on renewable gasoline, as you would expect. Whereas, the high hydrogen scenario on the right has a bit more hydrogen fuel consumption.

But total fuel use, as a measure of final energy demand is actually fairly similar across the three scenarios in 2045. Again, this is energy demand across all economic sectors statewide. What's different, really, is the magnitude of demand per sector.

Some of the nuances between the three scenarios start to become more apparent in the GHG emission side of the story, where you can see the effects on emissions in the transportation and electric sector in 2045.

So, on the left is the reduction over time in the high electrification scenario of GHG emissions. And on the right is another side-by-side comparison between the three scenarios. The electric sector emissions are lowest in the high electrification scenario at 13 million metric tons in 2045, because this represents a future in which other sectors are relying on the grid as a source of low carbon energy.

In the high hydrogen scenario on the right, you can see greater reductions in the blue, in the transportation sector due to increased use of hydrogen fuel cells. While the electric sector, in the red, has a little bit more room to emit at 19 million metric tons, as opposed to 13 in the high electrification scenario.

This slide shows statewide loads converted to the CAISO level over time, to 2045. Electricity loads vary by scenario and are a product of cross-sectoral interactions within each scenario.

As you can see in the first plot, electrifying buildings, transportation and industry, and hydrogen electrolysis are all key drivers of high electric sector loads.

And in the second plot, for biofuels, there's effectively zero load apparent for hydrogen production, but is otherwise similar to the first.

And then, the third plot, you see a significant wedge of hydrogen -- electric load for hydrogen production as you reach 2045.

So, this slide shows the electric load and GHG constraints translated from the PATHWAYS model into RESOLVE. The general process for taking the PATHWAYS outputs and importing in to RESOLVE was to first scale down the electric sector load and GHG emissions budget from the statewide PATHWAYS scenario, to be representative of the CAISO share, only. This is roughly 80 percent. And then, to sync up the PATHWAYS load forecast post 2030, with the IEPR load forecast pre 2030.

And then, to enter the manual -- enter the annual PATHWAYS load and emissions targets and then run the RESOLVE cases out to 2045, with the SB100 constraint applied in those cases.

So, what is the SB100 constraint? This gets to the definitional constraints, definitional questions that Ryan spoke about earlier. SB100 does not define zero-carbon resources. But for modeling purposes, staff had to make some basic assumptions about what counts toward SB100.

Renewables, nuclear and hydro are assumed in these scenarios to be eligible resources under SB100, post 2030, which is consistent with the first scenario Ryan described this morning.

Specifically, the RPS definition is retained through 2030, after which nuclear and hydro count as eligible.

The SB100 constraint is represented as a percentage of renewable and zero-carbon generation over total retail sales. This is similar to how RPS accounting rules work. And as modeled in RESOLVE, this does not necessarily prohibit gas generation. And this is because transmission and distribution losses are not counted as retail sales and they could, in practice, be met with GHG emitting resources. And also, exported renewable and zero-carbon resources or generation leaves room for some internal load to be met with GHG emitting resources.

So, as it turns out, all of the 2045 framing studies include some natural gas generation. The model makes economic decisions on how much gas capacity that's existing to remain, but must retain some gas plants in each scenario for local reliability purposes through 2045.

So, this figure shows RESOLVE results for the high electrification scenario out to 2045. Just a quick refresher on RESOLVE. RESOLVE is a capacity expansion model designed to inform long-term planning questions around renewables integration. It optimizes the selection of additional resources in the CAISO are needed to meet policy goals, including the RPS targets, GHG targets or our planning reserve margin.

Additional resources are selected by RESOLVE.

They're considered incremental to baseline resources. And baseline resources are those that are included in each model run as an assumption, rather than being selected by the model as part of the optimal solution.

So, what you're seeing here is just the incremental resources to the existing or baseline resources assumed in RESOLVE.

Some key takeaways are RESOLVE does not retain some thermal resources beginning in 2030. I don't know if you can see it from where you're sitting, but there's a tiny slice of gray bar under the X-axis there, beginning in 2030. That's gas capacity that the model chooses not to retain for economic reasons.

Solar and batteries, which are the purple and yellow, they dominate the portfolio mix, especially post 2030, where lithium ion batteries are assumed to have six to eight hours of duration.

Around 700 megawatts of long duration pump storage is selected in 2026. That might be really hard to see, but it's there.

And the maximum resource potential for onshore wind is built. That max is achieved out to 2045.

And you can see a small slice of biomass and geothermal in the later years. That's a little bit of red and green at the bottom, near the X-axis, which provides some resource diversity and firm capacity.

So, this slide shows key scenario metrics for each of the three scenarios in 2045. There's a lot of information here, so I'll point out just a few highlights. First, check out the fourth row down, that's effective SB100 percentage. This is the generation total as a percentage of retail sales. Or, you can think of it as a measure of whether and by how much the SB100 goal is met.

In each scenario, the percentage exceeds 100 percent. We have 109, 106 and 104 percent, respectively, for the three scenarios.

What this means is that more renewable and zero-carbon generation is procured to meet the GHG reduction targets than is actually required to meet the SB100 constraint in these scenarios. The GHG reduction targets being 80 percent below 1990 levels by 2050.

So, next, just below that, notice that almost all of the gas capacity is retained after 2030 due to the high peak load that's expected after 2030. The most that we see the model not retain is 4.8 gigawatts in the high hydrogen scenario, which is still less than a quarter of the total gas capacity on the system currently.

Finally, note that the levelized total resource costs of the biofuels and hydrogen scenarios is slightly lower relative to the high electrification scenario, which is a result of fewer resources, new resources needed to be built to meet the GHG targets of those other two scenarios.

This slide shows how the multiple constraints work in the high electrification scenario, as an example. RESOLVE portfolios, as I mentioned are the least cost solution to many different planning constraints, including the GHG emissions targets, the SB100 constraint, and the planning reserve margin, respectively the first, second and third plot here.

In each modeled year, one or several constraints could drive the selection of the optimal portfolio. And the constraint that drives portfolio selection incurs a shadow price to meet that constraint. Accordingly, a shadow price of zero means that the constraint is not impacting the optimal solution.

As you can in the bottom figure here, new investment in 2022 and 2026 is driven by a capacity shortfall. So, here, RESOLVE is picking new resources to maintain reliability, whereas policy targets, specifically the GHG target and the top plot drives capacity installation in most subsequent years.

Interestingly, the SB100 constraint, or the 100 percent retail sales by 2045 constraint, does not impact portfolio selection across the planning horizon. Meaning that reliability needs and the GHG target are the drivers of investment across the planning horizon and, therefore, they are the stricter constraints than SB100.

This slide shows results for a couple sensitivities, right on the high electrification base case scenario. So, first, we have the high electrification column, second is out-of-state transmission to new wind turned on as a sensitivity, and the third column is offshore wind available to the model.

Again, a lot of information on this slide, so I'll just point out the highlights. The first thing that really jumps out to me is the resource stack difference on the bottom. By allowing the model to pick new transmission to out-of-state resources, as you can see in the middle resource stack, it goes for over 20 gigawatts of new, out-of-state wind. And, yet, the total new capacity selected overall is about 40 gigawatts less than that of the high electrification base case, when it's not allowed.

The effect is similar, but not as dramatic, with the offshore wind sensitivity on the right, where roughly 10 gigawatts of onshore wind -- or, offshore wind is selected.

In both sensitivities, the availability of additional wind resources reduces both curtailment and total resource costs, while adding resource diversity, suggesting that these resources may have a place in the state's clean electricity future.

And, interestingly, both sensitivities retain a significant amount of gas capacity to maintain reliability relative to the high electrification base case, even with the large build out of new wind resources.

This slide addresses one of the main objectives of the study. How do the 2045 goals affect decision making in the 2030 time frame?

So, in the first two columns we have -- you can see metrics for two of the 2030 base case scenarios, run in IRP. We have 46 million metric tons by 2030, and 30 million metric tons by 2030. The first one is near the high end of CARB's established range for the electric sector, and 30 is at the low end of that range.

These scenarios have no visibility beyond 2030, so they solve for constraints only within that time frame.

But in the third column, you can see the 2030 results for the 2045 high electrification scenario. So, this scenario has that visibility post 2030 that the other two don't have. And so, as a result it makes different portfolio selection decisions.

So, as you can see, the new resource built under the 30 million metric ton case is similar to that of the high electrification scenario in 2030, which makes sense because the high electrification case crosses through roughly the same GHG emissions target in 2030.

On the other hand, the thermal retention under the 46 million metric ton case is more in line with the high electrification scenario in 2030. This is because in the high electrification scenario the model finds it more economic to keep that gas capacity around for the expected increase in electric loads due to the high electrification that show up not until after 2030.

So, now, taking this analysis back to the broader economy wide context, it's important to remember that the PATHWAYS GHG targets for the electric sector, as represented in each of the three scenarios assume maximum level of effort in each of the other economic sectors in California. And, therefore, you could say they assume an unprecedented decarbonization effort compared to the historical trajectory.

As you can see on the right, the sales share of electric heat pumps and zero emission vehicles would need to increase from single digits to more than 50 percent by 2030. That's in ten years. And for these goals to be realized, this is according to the PATHWAYS analysis for these 80 percent by 2050 goals to be realized.

And recent trends suggest that there are challenges in achieving those reductions. For example, the 2017 GHG emissions inventory showed a higher than expected emissions from the transportation sector. And, of course, there remains some uncertainty over the implementation of California's fuel economy standards.

This all raises a question I think that the SB100 group will be grappling with in future reports, which is how should the costs and risks of achieving GHG reduction in the electric sector be compared with those in the other economic sectors.

And, finally, these are some key takeaways from the study, most of which I've covered already. But to summarize, looking beyond 2030 it's helpful to inform near term thermal retention decisions at minimum.

New resource build in 2030, under the 30 million metric ton aggressive core policy case is similar to that of the high electrification case.

And under thermal retention under the 46 million metric ton case is more in line with the high electrification scenario in 2030.

All three framing scenarios rely heavily on solar and batteries to meet the long-term GHG goals and expected load.

Availability of out-of-state and offshore wind displaces instate solar and batteries, and lowers costs, and improves resource diversity.

And, finally, the PATHWAYS electricity GHG targets assume a maximum level of effort in the other sectors, but it’s not certain that those sectors will achieve those expected reductions.

Thank you.

MS. GUTERREZ: Thank you, Jason.

Okay, next we’ll hear from Arne Olsen, from E3, on Long-Run Resource Adequacy under Deep Decarbonization Pathways for California.

MR. OLSEN: Thank you. Arne Olsen, I’m a Senior Partner with E3. I’m going to talk today about a study that we published in, I think it was about May of this year, that was sponsored by the Calpine Corporation, that takes some of the questions that Jason teed up and examines them in some more detail in areas where the PATHWAYS and RESOLVE modeling hadn’t really gone.

And that's specifically the question of if you fast forward all the way through to 2050, and you've got a portfolio with lots of solar, and lots of wind, and lots of storage what additional resources might you need to supplement that system to make sure that you can keep the lights on during the times of the year when the sun isn't shining, and the wind isn't blowing, and that might have happened for several days in a row and your lithium ion batteries have been depleted.

So, it's really a look at resource adequacy and the need for firm capacity under these systems.

Just a disclaimer that this was a study that was funded by Calpine. It wasn't part of the IRP process. It's built on some of the models that the various state agencies have sponsored, but none of the agencies were involved in this particular study, and they don't necessarily endorse the conclusions that come from it.

So, the approach is kind of similar to the study that Jason walked through, which really is actually more recent. So, in a way, what Jason presented is more of an updated kind of version of some of this information, but then dialed into more of the CAISO load area.

But we started with the statewide PATHWAYS model that was really important in understanding what the need for firm capacity might be for the system in 2050, to make sure that you’re meeting long-run, very aggressive decarbonization goals.

So, we started off with scenarios that meet statewide, economy wide goals of 80 percent reductions below 1990 levels, and that comes out of our PATHWAYS model. And we also looked at a high electrification and high biofuels sensitivity. They’re not exactly the same as the ones that Jason talked about, but they’re very similar.

So, that information was then passed to RESOLVE, where RESOLVE develops optimal capacity expansion plans, the least cost way to meet the electric load that’s both endemic in the system, and the new loads that come out of the PATHWAYS model.

And also coming from the PATHWAYS model, which I’ll talk about, is a carbon budget that within the PATHWAYS framework has been allocated to the electric sector as part of an economy wide, least cost balancing of ways to meet that 80 percent reduction goal.

And then, the last piece of this, which is the one we hadn’t really seen anyone do a deep dive on prior to this study, which is, again, what do you need for reliability for resource adequacy throughout the year. And so, some of the scenarios we ran in RESOLVE we then tested in our RECAP model, which is a more robust model that looks at thousands of years of weather conditions, and how the load, and the wind, and the solar all match up, and how we might be able to store energy from one time to meet loads during another time. So, it's just a much more detailed, deep dive on that question.

So, just a little bit of background on the PATHWAY study. So, it was built on the Energy Commission's Deep Decarbonization PATHWAYS study that was published about a year earlier. This is the economy wide look, so all of the scenarios meet a 40 percent reduction below 1990 levels by 2030, which is the statutory goal. And then, from there they go on to meet an 80 percent reduction by 2050.

So, we then, for our two scenarios derived from that PATHWAYS work, an electric sector carbon budget. So, today, the electric sector in California emits about, let's say, 64 million metric tons. That's, you know, maybe about 15 percent of the total carbon emissions for the state, or the total greenhouse gas emissions for the state.

So, by 2050, it doesn't look like it on this chart because of the scales, but the electric sector has to reduce faster than the rest of the economy. So, the rest of the economy reduces from about 420 million metric tons to a little over 90 by 2050, and the electric sector reduces from 64 to between 6 and 10 million metric tons. So, now let's say, you know, between about 5 and 9 percent of the total GHG emissions for the state in 2050.

So, the two scenarios that we selected were really intended to be bookends on electric loads. So, bookends on this question of what firm capacity might you need to supplement the renewable and energy storage portfolios?

So, here we have both the high biogas scenario and a high electrification scenario. And the difference in them, really, as Jason alluded to, is how much electrification there will be of end uses in other sectors that currently use fossil fuels.

So, what we're showing here is conventional, so-called conventional electric loads and new electric loads between now and 2050. The gray wedges along the bottom are today's electric loads. And you can see that through very aggressive energy efficiency assumptions, we've just about kept today's electric loads flat for 30 years, and that's despite, you know, 30 years of continued economic growth, continued population growth. So, very, very energy efficiency assumptions.

And then, the blue wedges on top are the new loads that are coming out of PATHWAYS. So, on the left-hand side, you can see that that darker blue wedge for buildings is much smaller than the one on the right. All right, so if we have a lot of biofuels available in the economy, there are a number of uses for those. One of them would be to gasify those fuels and deliver them through the existing natural gas pipelines as a lower carbon form of methane, and use those in buildings. And that turns out if you have lots of this resource available, and it's reasonably priced, that might be a lower cost way of meeting some of those heating loads in buildings as opposed to electrification. There is still a lot of building electrification, even in that left-hand scenario, the high biofuels scenario, but there's less of it. And so, you can see that building wedge is smaller.

On the right-hand side, that scenario really relies very heavily on electrification of just about all of the space heating loads in buildings. Certainly, all of the light-duty vehicles in transportation. Maybe of the medium to heavy duty vehicles, certainly all the ones that are kind of local in scope. It's only the long-haul interstate transport that's not electrified in that high electrification scenario.

And just some statistics on the loads that come out of that, on the right-hand side there. But you can see the high electrification scenario has electric loads about 60 percent greater than today by 2050.

So, this slide shows you the portfolios that RESOLVE built to meet those electric loads. In the high biogas scenario, it builds about a total of 115 gigawatts of solar, about 20 gigawatts of wind, 3 or 4 gigawatts of geothermal. So, in effect the model is building, it’s maxing out geothermal, biomass and wind, and it’s scaling solar and storage to meet the load from there. That’s in effect what the model is doing.

So, the model would like to have more wind. We’ve restricted the amount of wind available in the state, just based on what the industry told us is actually available to develop in the state. We’ve restricted the ability to build out-of-state wind, with new transmission, to 10 gigawatts.

We didn’t have in this scenario, a year ago, good information on offshore wind. So, offshore wind isn’t available in these scenarios. In our more recent work and in the IRP work there is offshore wind. So, that’s a big addition and the model does like to pick that in the 2040, 2045 kind of time frames.

So, on the right-hand side you can see it builds 150 gigawatts of solar total, and between 50 and 75 gigawatts of energy storage. That’s it builds every one of the pump storage projects that we made -- that we know about and made available to the model. And then, it scales lithium ion from there. And it scales the power capacity and the duration separately, depending on what the system needs with cost functions for power capacity and lithium ion duration.

So, very, very large quantities of solar and storage selected. That's the dominant resource that's available and scalable in California and, really, throughout the rest of the Southwest, as well.

You can see back there, there is a small wedge of gas on the bottom, and I'm happy to be presenting after Jason because he talked about this already. But in effect, the model retains the natural gas generation to maintain reliability.

So, we didn't take the electric sector all the way to zero. We took it down to between 6 and 10 million metric tons. The way that the model chooses to use that small amount of natural gas generation is in large quantities, during only very limited times of the year. So, in effect, the model picks the power capacity of the natural gas based on the maximum demand that's placed on that resource.

That maximum demand, as I'll show you in a minute, occurs during a wintertime event, multi-day event of low wind and solar, and higher loads that are due to the electrification of lots of the space heating loads in buildings.

So, on the left-hand side, the high biogas scenario. That darker wedge on the bottom is gas generation in state. And that top wedge is the assumed amount of imports that might be available to meet our resource adequacy requirements. And there's some uncertainty about what that level might be, especially as other areas in the west decarbonize their own systems, and that's why we've called those out separately.

But in effect, on the left-hand side, in the high biogas scenario, it still needs 27 gigawatts of firm capacity, whether from instate gas or whether from imports. And that's down a little bit from today. It was 34 gigawatts total in 2020. So, it does find the ability not to retain all of the firm capacity.

On the right-hand side, in the high electrification scenario, because those electric loads grow very rapidly after 2030, especially due to the building electrification which has a wintertime load, it really -- it really can't retire any of the firm capacity.

So, it does, just for economic optimization, retire some instate and rely on imports more than it does today. There's a question about whether those imports really will be available or whether that's the right economic choice. I don't think that's really a meaningful distinction. I look at that 35 gigawatt number, which is the amount of firm capacity that the system has to meet.

And if I go back here, you know, there really isn't a firm zero-carbon resource available. And I'll talk about that in a minute. You know, we talked through this morning of what some of the definitions might be of more exotic technologies like CCS, of hydrogen, very long duration storage, and in some jurisdictions small modular -- let's say advanced nuclear, small modular nuclear reactors might fall into that category as well.

So, I think I mentioned this, but it's interesting to note that in every system that we've studied at these levels of decarbonization, the wintertime becomes the constraining factor. And even in the Southwest, you know, where the wintertime loads aren't nearly what they are in places like the Pacific Northwest, or Minnesota, or New York, or New England, but even here the wintertime becomes the most constraining event. And that's illustrated here on the top two charts. On the left-hand side is the hot summer week. That yellowish wedge is the amount of renewable generation on an hourly basis over several days. And the dark line is the electric load.

You can see every, just about every day in the summertime there's a significant amount of surplus generation available during the high solar hours that can be stored and used at night.

But even there, there's a little bit of variation. So, that first day on the left tops out at about 150 gigawatts of renewable generation. But the one on the right is down to about 130. So, even in the summertime, because so much of the energy is coming from a weather dependent resource, there are still times when that weather doesn't cooperate. So, on that last day there, there is some gas that's burned at night to keep the lights on. And even during the most abundant time of solar during the year. That could probably just be taken care of, if you really needed to reduce the carbon more, by adding more solar and more batteries.

But the one on the right-hand side is much harder to solve. To, this is where you have a multi-day event, where it's cold, you have multiple days in a row where the sun's not shining, and the wind's not blowing, and that's very, very difficult to solve with lithium ion. Kind of diurnal pattern batteries, so you need longer duration batteries. So, we call this firm capacity is what's needed to solve this challenge from capacity. It's just defined as a resource that you can turn on when you need it and it can produce energy over a long duration. And how long? This example is three days. It might need to be four. It might need to be seven.

So, we need some firm capacity. So, what happens if you try to start from where the model ended up as the optimal portfolio to meet, let's say, that 10 million metric ton target and go from there, and if you don't have a firm zero-carbon resource.

This slide's kind of busy, so I'm just going to walk you through it kind of step by step here. But on the left-hand side is the optimal scenario, with 25 gigawatts of gas, plus the 10 gigawatts of imports. You can see that's the solar and storage portfolios that were build.

If you were to force retire 15 gigawatts of gas, what the model would build to replace that is a little bit more solar, 10 percent more solar, but a whole lot more storage. So, now, it's building 94 gigawatts instead of 74, but it's building 17 hours of duration. Because you say they had that, those multiple-day events where it has to try to -- it has to discharge over a very long period of time. So, it really needs a lot of duration to make up for the fact that you don’t have that resource that you can turn on.

Then, if you try to take the gas all the way down to zero, in other words try to eliminate carbon from the portfolio, in the absence of a firm zero-carbon resource, and it really only has wind, and solar, and batteries, it has to massively oversize the renewable portfolio by two and a half times. So, it’s now, instead of 111 gigawatts of solar, it’s building 250 gigawatts and it’s building 150 gigawatts of 15-hour batteries. That’s five times as much storage duration as you had over here in the 25 gigawatts of gas case.

So, what is the cost of that? This middle scenario, moving from 25 to 10 gigawatts of gas costs an extra $28 billion per year relative to the reference case, which starts off at a revenue requirement of about $109 billion per year. And to go all the way to zero, this now adds $65 billion per year to the cost of electric service in California. So, very, very costly to reduce those last few million metric tons of emissions in the absence of a zero-carbon firm resource.

And just to complete the picture here, the marginal abatement cost is in the order of 6 to 20 thousand dollars per ton. So, clearly, there are other things that we can do besides this to reduce carbon emissions more cost effectively in other sectors.

So, key findings of the study is a least-cost plan for meeting the economy wide goals reduces electric sector emissions more rapidly, more deeply than the other sectors, down to a range where we got to about 6 to 10 million metric tons. So, 90 to 95 percent below 1990 levels.

So, to get the economy to 80 percent, the electric sector's going to 90 to 95 percent to do that in a least cost fashion. But it doesn't require a complete decarbonization of the electricity supply.

And I would argue that if you don't have a firm zero-carbon resource available, it's counterproductive to try to reduce carbon all the way to zero with just the wind, and solar, and batteries. Because of the main plan for decarbonizing buildings and transportation is electrification, then that really needs to be an attractive economic proposition for the consumers that you're asking to adopt electric vehicles and to buy electric heat pumps. So, you really need to be careful about electric rates and making sure those electric rates are reasonable if you're relying on electrification as your main strategy for decarbonizing much of the rest of the economy. So, it's probably counterproductive to go too far in the electric sector.

Again, that's in the absence of a firm zero-carbon resource. So, if you have a firm zero-carbon resource, then a lot of things change. The categories, the candidates there are fossil generation with carbon capture and sequestration, advanced nuclear, very long duration energy solar, multiple days, perhaps weeks of energy storage, or some form of zero-carbon gas, whether that's biogas, whether that's hydrogen, or some other form of fuel that you can use perhaps in the existing infrastructure.

In the absence of that, the system retains 17 to 35 gigawatts of firm capacity. It would be costly and impractical to replace all gas generation with wind, solar and storage. And we've tested this on a number of sensitivities and we've found even at 3 million metric tons in the electric sector, the model still retained 23 gigawatts of firm capacity. So, it's a very, very robust to all the various sensitivities that we tested.

So, thank you.

MS. GUTERREZ: Thank you, Arne.

So, now, we will take it down to a regional level and we'll start that off with James Barner from LADWP, presenting on LA100.

MR. BARNER: All right, thank you. So, back in -- let me forward a few. There we go.

All right, back in 2016, the LA City Council directed the LADWP to partner with DOE's Renewable Lab to conduct a 100 percent renewable study. The motion also requested LADWP to establish a stakeholder process.

The main goal of the motion was to determine what investments should be made to achieve a 100 percent renewable energy portfolio for LADWP. And the original motion was amended to add an assessment of jobs and economic development, incorporate the CalEnviroScreen, and prioritize environmental justice neighborhoods as the immediate beneficiaries of localized air quality improvement and GHG reduction.

And there was a requirement to perform an analysis by the ratepayer advocate on how the 100 percent renewable scenarios fit within the current rate structure.

So, per the City Council motion, LADWP retained the National Renewable Energy Laboratory, also known as NREL, to conduct the study. The study is the largest renewable energy study that NREL has ever performed. Some of the models within LA100 require higher performance computing. Some of the analysis would take 20 years to run on a laptop, just to give you the sense of the amount of data we're dealing with.

Another instruction from the City Council motion was to create a stakeholder process for the study. For this, we've assembled a group of stakeholders, whom we refer to as the Advisory Group, or AG. The Advisory Group meets quarterly to provide input and guidance to steer the study in the right direction.

This diagram summarizes the scenarios that NREL is considering for LA100. There are essentially four main scenarios that are each considered under moderate and low electrification scenarios. The left-hand being the blue, is the moderate. And the right, the green is the high load electrification scenarios.

The ninth scenario considers a high load stress version of SB100, which is on the far right, in orange.

All of these scenarios reach 100 percent renewable energy by 2045, except for the scenario known as LA Leads, which examines accelerated timelines of 2035 and 2040.

The study also includes a reference case that uses LADWP's 2017 IRP, which was the approved plan for LADWP before the enactment of SB100.

Only SB100 and high load stress cases allow use of existing natural gas and RECs in the final year of 2045. No new natural gas is allowed in any of the scenarios considered.

The Transmission Renaissance scenario allows for new transmission corridors. While others, like SB100 and LA Leads and Emissions Free, only allow upgraded or new built transmission along existing corridors.

The High Distributed Energy Future scenario doesn’t allow for new transmission to be built. Instead, the focus is on distributed energy resources.

Climate change and associated temperature increases are being incorporated into the load forecast used in these modeling.

This is a block diagram of the models that comprise the LA100 study. Each block represents a model or set of models and each line between the blocks represents either data or knowledge handoffs between the models. So, you can see that the modeling in the study is extraordinarily complex. It’s easier to digest this overall model in pieces, so I’m going to step through seven components of the model and describe what each achieves in isolation.

So, this is the demand side grid, DS grid model. It uses a bottom up approach to drive hourly electricity consumption profiles. NREL is developing a city scale version of their US wide model that is specific to Los Angeles. This involves millions of simulations that require high performance computing.

The DS grid model comprises multiple input component models that model loads stemming from the commercial and residential building stock, the industrial sector, the transportation sectors. Specifically, the adoption of plug-in electric vehicles and their charging profiles. And other electricity use that is not covered by the above models, is modeled within the GAP model.

Next is the distribution generation market demand. This is called DGEN model. It's a type of capacity expansion model that simulates how residential, commercial and industrial customers will adopt distributed energy resources through 2050. The DGEN model uses a bottom up approach and dates a number of assumptions, including those related to future electricity cost, technology cost, technology performance, policies, regulations, and customer behavior.

Distribution analysis is performed using the open DSS module and it has the following features, including estimating the hosting capacity of individual feeders to determine the amount of demand growth and distributed generation that can be accommodated. The module also performs power flow analyses to identify feeders subject to voltage and thermal violations, and estimates the cost of required upgrades to feeders.

The core of the LA100 modeling is the capacity expansion model, known as Resource Planning Model, or RPM. RPM estimates how the capacity of the grid can be expanded as LADWP integrates renewable resources. In short, the model identifies what to build, where to build it and when.

Inputs to the model include projects of load, fuel prices, policy changes, technology costs, and technology performance.

Outputs of the model include simulations on how regional generation and transmission systems will operate and expand. In RPM it seeks to minimize the overall cost of the system.

After RMP output is a plan for expanding LADWP's resources, multiple models are used to validate the output. The Integrated Grid Modeling System, IGMS, is a new type of analysis that studies reactive power flows between the transmission and the distribution system in the presence of high DER deployment.

The Probabilistic Resource Adequacy Suite, PRAS, is a model used to better understand the adequacy of each investment pathway. NREL is performing production cost modeling using PLEXOS, for up to five-minute dispatch.

And lastly, for power flow and dynamics analysis they're using PSOF, which evaluates power system voltages and phase angles, as well as real and reactive power that is flowing through the system.

NREL is working with USC, one of the AG members, to model the impacts of renewable energy on air quality, with consideration given to environmental justice communities. NREL is using its capacity expansion model, RPM, to estimate the GHG reductions that will occur in response to the use of 100 percent renewable energy.

The models will simulate changes in the following sources of pollution. The power sector, with a focus on LADWP's assets, light-duty vehicles, residential and commercial buildings, and the industrial loads of LAX and the Port of Los Angeles. USC is using a three-dimensional, gridded, photochemical air quality model.

And for economic impact and jobs analysis, NREL has subcontracted to a subcontractor who's developed a model to estimate the economic impact of converting to 100 percent renewables. And the key outputs of this model are estimates for employment, and impacts on household income and GDP.

So, here are some of the fundamental challenges being considered in the study. We don't have a lot of results at this point. But there are fundamental economic and technical challenges to achieving a 100 percent renewable energy power system. One of the most critical is the mismatch of variable renewable energy supply and electricity demand. This mismatch has both a daily diurnal and seasonal component, and this leads to an increasingly unusable amount of energy as we increase the contribution of renewable energy.

This particular illustration highlights the seasonal mismatch in timing between renewable energy supply and demand to meet 100 percent of annual demand for LADWP. And each dot on this represents one day of the year. And you can see curtailed energy on the left-hand side. And on the right-hand side, for energy deficiency, the net load megawatt hours.

So, here, you can see that simply adding more variable generation provides diminishing economic benefits. At about 95 percent renewable energy, we've heard additional energy is simply not needed on most days of the year and adding more solar or wind will provide no benefit on those days.

In this example, only about a third of the output of a PV system will actually be useful by LADWP's customers, without additional mechanisms to better align seasonal supply and demand. And this example is without a lot of long-term storage.

To meet load, this scenario shows -- shown, requires an abundance of renewable and seasonal storage. This example week, in December 2045, shows that with high variable renewable resources and without using natural gas generation, there's occasionally not enough energy or power to serve customers, as shown on the chart as unserved energy.

You can see that on all, except the first day, there is no curtailed energy. Meaning that there's no additional excess daily energy available to charge storage resources.

This is an example of the build out using the capacity expansion model RPM. Please note that this is very preliminary results and it doesn't consider high loads.

This part shows how the technology or capacity mix changes through time for any given scenario. In these examples, the resources required under these scenarios require an expansion of replacement resources of between 155 to 164 percent by 2045.

Between 2025 and 2045, more solar, and storage, and wind is built. And long-duration storage, assumed to be hydrogen fuel cells, is built in one of the scenarios to manage the mismatch of energy from spring to summer.

Combined cycle, and combustion turbine, and peaking units are eliminated in most of the scenarios in 2045.

Reaching 100 percent RPS requires a heavy reliance on out-of-basin generation and transmission lines. Concerns regarding grid resiliency are being considered in this study. In light of recent fires which significantly reduced LA's import capacity, back in October, there was some concern for having such a heavy reliance on a few external transmission corridors to import energy without sufficient local, dispatchable generation for emergency backup.

Limitations to available transmission import capability is a concern and sequencing and duration of transmission outages for scheduled maintenance becomes critical to charging battery storage in the LA Basin, especially while having to also serve existing load.

And we have to be cognizant that if LADWP's transitions to 100 percent renewable energy is too expensive, the higher electricity cost could discourage building electrification and EV adoption, which are two crucial strategies for reducing significant, citywide

GHG emissions.

So, here are very preliminary results. What we've learned so far, as mentioned before, our preliminary findings are showing a large amount of solar, battery storage, and wind is crucial. Storage is used to shift energy mainly from solar, from daytime to evening hours. And when thermal generating assets are not available, long-term storage must be used to shift energy from spring to summer.

In scenarios which allow renewable energy credits generating assets, which are not eligible for renewables certification, can be used when the power system is stressed. And when a large amount of renewable energy resources are online, the model will often decide it is more economical to curtail renewable energy than build out more storage.

And this is the LA100 study timeline. As you can see, our initial modeling results are coming out in December of this year. The results will be updated to consider the impact of no OTC repowering in March 2020, so those gas units won't be included in those results.

In September 2020 we'll get the final modeling results and the final report in March 2021.

And if you'd like to find out more regarding the LA100 study, shown there is the link. Thank you.

MS. GUTERREZ: Great. Thank you, James.

And, finally, we have Erica Bowman from Southern California Edison, presenting Pathway 2045 Report. And I'd like to invite you guys to stick around in case we have any questions or comments from the dais after. Thank you.

MS. BOWMAN: So, thank you. I am Erica Bowman. I'm the Director of our Resource Planning and Environmental Strategy groups at Southern California Edison.

I'm just going to get right into it. It's very similar to what -- our results are very similar to what you've heard across the panel. But just to give you a little bit of context of what SCE did, back in 2017 we released our Clean Power and Electrification Pathway Report, where we really focused on 2030 and how we thought it was the most cost-effective and feasible way to hit our 2030 decarbonization goals from a statewide perspective.

And as you can see there, it was decarbonizing the electric sector to 80 percent, and then electrifying 7 million light-duty vehicles, as well as electrifying almost a third of our space and water heating in buildings.

So, in 2018, Governor Brown issued his executive order for both carbon neutrality, and then also signed the bill for SB100, which we really thought moves the ball forward in how we need to think about the long-term implications of decarbonization, especially given that in this context it would certainly be that the electric sector would need to lead in terms of decarbonizing even further and faster, as noted earlier.

So, in our recently released white paper, Pathway 2045, we did the same type of economy wide modeling, using the E3 PATHWAYS model initially, and then we did similar processes as these other folks have done on the panel, where we're looking at our resource portfolio build out using a capacity expansion model. We don't use RESOLVE. We actually use an ABB capacity expansion model, so you see a little bit of different results there. And then, we also put this into a production cost simulation model to look at some of the reliability issues, and we use PLEXOS for that.

In addition to doing kind of the resource adequacy, as well as the cost production modeling on the resource side, we also then gave our results over to our transmission and distribution folks, and they did their detailed analysis to look at, okay, if these are the resource scenarios that we need to plan to, what do we need to do on the transmission, on the distribution side of things in order to make certain that we're able to deliver this resource to the customers.

So, this really just kind of highlights the main factors, or the main carbon abatement mechanisms that are being used to achieve the economy wide decarbonization goals. So, by 2030 we're saying we need about, again, 80 percent of our electric grid should be decarbonized. And that would be used, then, to support over, around 7 and a half million light-duty vehicles.

And then, similar to our 2017 study, we are anticipating that we need to electrify around a third of our building space and water heating.

Additional to that, we see a reduction in pipeline, in natural gas pipeline consumption. That really is coming because you're electrifying your buildings, and so you're reducing your natural gas. And then, you have a biomethane component of that remaining gas.

So, by 2045 you're seeing a significant amount of light-duty vehicles needing to electrified to 26 million. That's really around 75 percent of all vehicles. Then, you have building electrification around 70 percent. And then, we you have pipeline gas reducing to almost half of today's levels. And 40 percent of that is biomethane.

So, some implications from this intense electrification out in 2045 is that you do see load growth. It’s something that we haven’t really seen, again as mentioned previously. It’s something that I think is one of the key components of when we think about SB100 and complying with SB100. This is really an important piece.

And I think as we think about decarbonization and being successful in that, in the State of California, one of the issues is what are we doing to make certain that both the transportation electrification is happening at the pace that is needed? What are the incentives, especially in the early term through 2030 to get there? As well as what are we doing on the building electrification side?

Because across all of these studies, including in the scenarios where it’s hydrogen and biogas, you’re still needing a lot of electrification to get there. And so, I think there’s some real key questions that will be driving kind of what we see on the electric side, but it does really -- it is embedded in this load picture.

Additionally, we did have a lot of capacity on the distributed energy side, so we had about 30 gigawatts of solar capacity being built, which is roughly about 50 percent of households, of single-family homes having solar deployed in 2045. Additionally, we had about 10 gigawatts of behind-the-meter storage that we were seeing as we build out our scenario.

So, we ran two resource capacity expansion scenarios after we look at kind of the high electrification case. One is looking at what we called the balance scenario, where you're seeing more balance between solar and wind development. A lot of that wind is coming from out of state.

And then, we also have the solar heavy scenario, where you're looking at more solar resources being deployed in lieu of out-of-state wind. And in the solar heavy scenario we said we wouldn't be -- we wouldn't be allowing for any more imports into the State of California. And it's really the CAISO footprint, I should clarify. And so, that really restricted the amount of out-of-state wind that you could bring into California, itself.

What was interesting, when we went through this exercise, we handed off these two scenarios to our transmission and distribution planners, and when you lay on top this is not looking at it from a capacity stand point, but more it's a total direct cost in billions, you see that on the solar heavy scenario you have a lot less transmission and distribution costs. And, really, it's the transmission that's the big driver driving difference.

On the out-of-state wind scenario, or the balance scenario, you're seeing a lot more transmission needing to be developed not in California in order to bring those megawatts to the border, so that California can use them.

I think, really, this is a starting point for a conversation. There's a lot of things that we can talk about. What resources will be available, could be available, at what cost?

We did model offshore wind as a technology that could be used. Our model did not select that. We may have had different assumptions around that compared to other models that did see some offshore wind development happen. We also modeled some advanced geothermal, et cetera.

But this is an important piece and I think we need to think through some of these things because there are real tradeoffs. On the whole, they're pretty much similar in terms of costs. I don't think, really, one is better than the other, especially given the underlying uncertainties and all the assumptions we're currently making for 2045. But it's something that I think, as we think through what could be the real limitations in this type of development going forward is really where we need to spend our time.

And then, one other piece, just kind of to highlight here, is talking about the load shape itself. So, depending on how peaky your load is and what kind of ramp you're showing, it can really drive cost savings on a day-to-day basis.

So, in this graph we're showing -- the blue line is what we used in our modeling, in our cases, but we did a sensitivity saying, okay, what happens -- because we did embed a lot of flexibility. So, there was flexibility in our building loads, as well as flexibility in our transportation electrification loads.

So, this is really looking at what if our load was less flexible? What if it's not being managed as well as it could be or should be, what happens?

And you can see that you end up spending about one, to two, to three billion dollars more each year because you're not managing that load. Obviously, if you're able to even further minimize the ramping between -- in that original load shape, you'd see additional savings.

And then, I think I haven't seen a lot of studies trying to come at it from an affordability perspective for a customer. So, what we tried to do was take all of the investments that we were seeing that needed to happen on the energy side of things, and not look at just from an electric rate perspective, but put it in the context of a household energy expenditure perspective.

So, how much are customers spending today and how much do we expect them to spend in the future on different equipment in their homes, and for their cars, et cetera, in order basically to either live their lives in a modern way, or to -- obviously, for their transportation.

So, this is looking at SCE territory only. And you look at what the non-adopter looks like versus what an adopter looks like. So, even today, if you have folks that are adopting electric vehicles and also adopting home solar systems, they are saving. And that in today’s numbers we are assuming certain benefits, such as a NIM tariff, et cetera, on the solar side. This does exclude the capital cost of investment, so we’re not -- so, if you go out and buy a car and the amount of money differential between a new electric vehicle versus an internal combustion engine vehicle, that’s not being captured in this analysis.

However, the investment for the capital

expenditures in the electric sector, itself, is being captured because we did a rate analysis to look at that.

But it is showing that in 2045 we are spending less relative to today, because you're basically taking out gasoline and natural gas costs.

The other piece I do want to highlight here is that the natural gas costs, shown in this affordability graph, assumes that the same amount of revenue requirement is needed on the natural gas sector, and the customers are reducing. And so, you're having a much bigger burden being put on those remaining customers. Basically, the ones who haven't adopted electric technologies.

So, that's also a point of something that needs to be resolved as we move forward into the energy transition in terms of, you know, how do we want to transition appropriately and equitably so that those folks who may not be able to adopt new technologies are also not paying double for the lack of being able to do so.

And that's all I have. Thank you.

MS. GUTERREZ: Thank you, Erica.

At this time, we will invite our Chair Hochschild and Commissioner McAllister to make any comments or ask any questions of the presenters.

COMMISSIONER MCALLISTER: So, that's great. Thanks, all of you for presentations. And it's actually notable, I think, how much concordance there is across their message here. So, it's nice to see this kind of not quite consensus, but it's nice to see kind of similar things coming forth. And I think that will be really helpful to organize the conversation going forward.

I guess, I really appreciated Edison's slide 6. Erica, maybe we could pull it up just real quick. And I guess definitely I appreciate your sort of highlighting the fact that the TND investment varies by scenario. That makes sense, right. But, you know, I think a lot of people that are not in utilities don't have a lot of visibility into what is driving those investments. You know, the distribution system, like what kind of enhancements are needed depending on how demand evolves. And then, whatever happens or doesn't happen on the distribution on the distributed level has implications for what has to happen west wide and with transmission.

I guess, I want to ask about assessment tools, and I guess this is for everybody, really. In terms of how we assess reliability under these different scenarios, do we have the tools we need to go relatively granular? Like understand the equity implications, for example, the locational implications on reliability of these different scenarios?

MS. BOWMAN: So, I would say the question is how many scenarios do you want to look at? And, sure, we do have tools that can assess that at a granular level. But the time it takes right now to do that assessment, at that granular level, is very high. And even for us, I mean we, in our planning cycles like it just becomes very difficult to do multiple scenarios and feel like we're really confident. And especially, as it relates to cost, to be able to just get through the work. Because the more granular we go, it becomes harder and harder as you build on more scenarios.

So, I guess maybe the question is do we have the right tools to do a lot of scenarios in a timely fashion? Probably, that needs to be developed. But, yes, can we do it through brute force analysis, yes, we can look at that.

COMMISSIONER MCALLISTER: I see. So, maybe a slightly different question would just be how different are the scenarios -- how different are the outcomes of those analyses depending on our assumptions for how successful we are on electrification, say, at the local level. And maybe that's really the question I wanted to ask.

MS. BOWMAN: I think, certainly, it’s really dependent on how successful we are. Because under -- really, the driving costs for the scenarios that we modeled was the underlying load picture. And that underlying load picture was assuming that we hit a very high number, three-quarters at least in 2045, of electric vehicles being electrified. Or, sorry, of vehicles being electrified.

So, given that, like that is a huge number. And if you look -- I don’t know what slide number it is, but if you go -- oh, I can control it, I’m sorry. If you look here, in the red that is your transportation electrification load. So, even if you have that, that’s going to have a significant impact on what your resource build out will need to be, because you’re just not going to have to serve as much load as you would have.

Now, will you actually meet your decarbonization goals? I don’t know, it would be very difficult. You, obviously, either need hydrogen which would then increase your electric load because you’re using electricity to create that green hydrogen, or you have biogas which, again, I think it’s a question, I think you’re seeing electric vehicles still winning out in terms of on the light-duty level that they need to be electrified to hit those decarbonization targets.

COMMISSIONER MCALLISTER: Yeah. Why don't we give others a chance to, yeah, add onto that.

MR. OLSEN: If I might, I think we understand the reliability challenges at the system level fairly well.

COMMISSIONER MCALLISTER: Yeah.

MR. OLSEN: You know, I don't think -- I think there's a lot of uncertainty about how flexible we can make a lot of the loads, especially the transportation load. That's potentially a big load that you could think about being flexible, but the transportation needs are also very important to individual people. So, you know, there are some limitations there.

But I think your question about the impact of the electrification load at the distribution level is really, really important. When we do studies of higher electrification, what we typically find is there's some head room on the existing system. So, typically, we find that it actually reduces rates to put a certain number of electric vehicles on the system. And a certain number of heat pumps, again depending on the shape of the electric load and whether that's a winter peaking or summer peaking distribution system. But it can reduce rates to add some heat pumps.

But at a certain point that curve starts to tilt the other direction just because you're now having to upgrade the distribution systems from the home all the way up through the substation, to the subtransmission level. So, I think there's a lot of investments. I don't think we fully understand how large that number is going to be. But that's going to be really, really important to do everything we can to minimize the level of distribution investments and make the loads as flexible as we can so that we can save on those costs.

COMMISSIONER MCALLISTER: Totally, totally agree. And I guess, you know, maybe it's not necessarily like if we -- maybe we build it and they don't come. I mean, I think those things are codependent, and then your planners can manage that as it comes about. But if we're aiming at this long term, we need to make sure we're planning for the load that's actually going to show up, and then encouraging that load to actually show up and that flexibility to show up at the same time. Otherwise, we're kind of not going to get there.

MS. BOWMAN: And I would also add on just one other point on at least the distribution level as it relates to transportation electrification. Also, the rate at which you want to fill your cars or, you know, charge your batteries, that has a big implication for what kind of upgrades you're going to need at the distribution level.

COMMISSIONER MCALLISTER: Do LADWP or PUC want to chime in on this at all? No. Yeah, go ahead.

CHAIR HOCHSCHILD: Yeah, I just -- first of all, to your last point I think it is the case that as the range of electric vehicles increases, and that's happening across the board now, we have a little over 45 models on the road today. We'll have 140 in the next two years. And vehicles like the Ford F-150 are coming.

As the range increases, actually, your range anxiety goes down. I got the Chevy Volt, which the *Wall Street Journal* called the -- what's the word, what's the drug for anxiety, Xanax or whatever it is. That would have been for range anxiety, right.

And so, actually, you can use level 1 charging, which is a lot less costly.

But let me, this is more of an observation than a question which is, you know, as we're sitting here meeting this morning, about 30 minutes ago, PG&E announced they're going to cut off power to another three-quarters of a million people this week. So, this is the world we're in, right.

And, you know, this is a larger problem than just for our goals here. This is affecting the whole state and our economy and, you know, many levels. And it affects also the gas system. In the past, they've actually cut off some of the gas system as well.

I want to say my belief is that this is a solvable problem. Okay. We had the symposium with Germany last week, which the Energy Commission hosts once a year. So, Germany's divesting from all of their nuclear and all of their coal. Their average downtime for the electric grid in Germany is 12 minutes a year. Okay. And I think that's where we need to drive to.

It is, you know, not a silver bullet solution. It's silver buckshot. There's many different things to control demand, and including microgrids. You know, we funded microgrids on, you know, 38 different sites, $85 million. You know, it was many, many different dimensions to this. But, I mean, the importance of grid reliability has, you know, elevated significantly. And I think that's on everybody's minds as we go forward. Asking the question how can these things best support? How can everything we add, from electric vehicles to electric heat pump water heaters be good citizens of the good.

And I think if we do that right it is solvable. I do believe that. But it's very clear to me the electric grid has to be the green backbone of our climate strategy and so, the reliability, which has always been important, but especially so now.

I just want to thank all the panelists. Really terrific contributions, thank you all.

MS. GUTERREZ: Okay. At this time we will just have you stay put and we will start with public comment. If you can, please fill out a blue card and give it to the Public Adviser.

We will start with Eddie Ahn, from Brightline. You may need to turn that mic on.

MR. AHN: Hello. Oh, great. Good morning, Commissioners, Eddie Ahn with Brightline Defense, and environmental justice organization that originally supported SB100 and we're excited to see this process well underway through the workshops.

Just two brief comments, the first of which is just want to make sure that in addition to considering the impacts in energy equity around barriers, and impacts to communities that we care about, low-income communities, environmental justice communities, that we're also making sure that we mention jobs, and also economic benefits to our communities as well.

So, I was particularly excited to see in the LADWP presentation mention of an economic analysis that's been done around their planning process, and making sure that's incorporated as part of SB100's technical workshop will also be important.

Also, appreciate the environmental justice focus as well in the LADWP presentation. And as well as highlighting certain portions. Light-duty vehicles, for instance, is mentioned repeatedly. But how can we make that beneficial to communities, again, that we should be caring about in the State of California.

The second point to segue into is just reliability in the grid and just making sure that's emphasized again and again. Commissioner Hochschild has made very good comments about how we need to ensure reliability in the grid through things like microgrids. But also want to make sure that we're ensuring the diversity in our energy mix, as well.

And one of the things that we'll continue following at Brightline is, for instance, the possibility, the potential of offshore wind. Making sure that that can also add on to things that we have advocated for in the past, such as rooftop solar.

Thank you.

MS. GUTERREZ: Thank you, Eddie.

Next, we have Maya Batres from the Nature Conservancy.

MS. BATRES: Hi, thank you. And thank you for the opportunity to provide comments today. My name's Maya Batres, on behalf of the Nature Conservancy.

First of all, we're encouraged to hear that the agencies are thinking about how to include environmental impacts as part of the quantitative analysis for the SB100 report. And we want to express our support for this effort.

TNT believes that incorporating land use considerations early on into energy planning is a key step to achieving SB100 goals and that a robust environmental dataset should be considered as part of this analysis.

Our recent report, which we conducted with E3, the Power of Place, we submitted as part of our formal comments through the scoping workshop, shows that incorporating land use data and energy models can improve planning forecasts, limit future development conflicts, and avoid the loss of habitat and ecosystem services.

Furthermore, the inclusion of land use data significantly influences the types and quantities of resources selected, the amount of land needed, and the optimal location for build out, as well as the costs for the scenarios.

Understanding these variables can help inform policy decisions that can lead to environmental benefits, cost savings, and predictability for stakeholders.

So, I just want to highlight a couple key outcomes from our study that speak to why this is so important. First of all, the amount of land needed to meet SB100 goals is significant and varies depending on the level of environmental protection.

From our report, out of 61 scenarios, we find that anywhere from 1.6 to 3.1 million acres are going to be needed to achieve SB100 goals.

Second of all, without a plan to limit impacts to natural and working lands, the impact to agricultural land is high. Anywhere from one-third to one-half of development will occur on agricultural lands without a proactive plan.

Third of all, our scenarios show that achieving the best land outcomes at the lowest costs happens when resources are shared across the west. This is something that the agencies should be considering throughout this process.

Through the innovated resource plan process, the CPUC, the CEC and the CAISO have developed a process for incorporating land use data into energy modeling, and we encourage the same to be done throughout the report.

Finally, we believe that incorporating land use data in the SB100 process is consistent with the state's policy to protect and manage for natural and working lands when it considers new policies and complements other efforts that the state is undertaking to identify low impact locations for clean energy.

We look forward to the opportunity to work with the agencies and other stakeholders as it relates to the recommendations today. Thank you very much.

MS. GUTERREZ: Thank you, Maya.

Next, we have George Peridas from Lawrence Livermore National Laboratory.

MR. PERIDAS: Chair Hochschild, Commissioner McAllister, thank you for the opportunity to testify today. Panelists and staff, thank you for your excellent presentations.

I think the magnitude of the task is becoming very clear and it would be misguided and even hubristic to assume that we can linearly chart a course and then stick to it. I think we're going to need as many dogs as possible in this fight. And there are many dimensions, including cost and reliability that factor into this task that we have ahead of us. And we need to make sure that we diversify our approach to the extent possible.

I've had the pleasure over the last three years to convene a group, a very diverse group of labor unions, NGOs, industry participants, researchers, specifically on the topic of carbon capture and storage. And we've come together with the common objective to see this feature in California's energy mix and to provide useful solutions and useful services.

So, I was particularly happy to see this morning, in the staff presentation, that a broader view is envisioned at this point by the agencies on what may constitute a zero-carbon resource. And we believe that carbon capture and storage may also have a role to play and it should be allowed to do so.

I would encourage you to think more broadly. I think limiting it to natural gas fuel only may be too narrow. We're currently in the process of finalizing a report on how, we being the lab, how California can achieve upwards of 100 million tons a year of negative emissions to aid with its goal of becoming carbon neutral, economy wide, by 2045. And there are many pathways in which you can achieve that. And using waste, biomass, among other things is one of the ways that can yield you very large amounts of negative emissions.

So, in considering the goals of SB100 here and implementation, I would urge you to go beyond just the use of natural gas. I mean, using biogas from various feedstocks may also be very much in play and useful.

So, we look forward to continuing the conversation. And may I also add that Chevy Volt has other uses. During the latest PSPS outage, I was actually able to reverse the flow of currents and instead of charging the car, I was able to run the fridge and the lights at home using the car's battery. So, other synergies here that we look forward to. Thank you very much.

MS. GUTERREZ: Thank you, George.

Next we have Ryan McCarthy from the California Hydrogen Business Council, followed by Ed Smeloff from Vote Solar.

MR. MCCARTHY: Hi, Ryan McCarthy here on behalf of the California Hydrogen Business Council. First of all, I want to say thank you for all the workshops you have done and for today's in particular. This is an impressive body of work that the state has put together as it considers its path forward.

One question I have is how, and this obviously doesn't need to be addressed now, but how over the course of the next three or four months the state is going to pull this all together and resolve, you know, the definitional scenarios we heard today, where any natural gas, for example, has to have carbon capture. With all the studies here, many of which include a lot of natural gas in its current form as well.

But one observation on the technical analyses here, I think the fact that -- well, first, I would agree with the last statement that we should keep our options open and avoid locking in, and making decisions now based on these analyses, which are very uncertain given everything that's uncertain currently about the electricity system. But also, the differences in costs reflected in the different scenarios I imagine are dwarfed, you know, by the uncertainty and the assumptions. So, I think we should just keep that in mind.

I think the assumptions that go into some of the modeling in the IRP, if I'm not mistaken, I think some of the renewables costs in 2050, for example, are higher than the costs we're seeing today. I think, certainly, lithium ion battery costs are higher than the costs we heard quoted from the Chair this morning. So, just, you know, keep in mind, you know, we need to understand what innovation will do.

And I think the fact that, you know, we heard that SB100 goals are not the constraint, that reliability is the constraint, it seems like something's still missing in these scenarios. I imagine that could be hydrogen and other long-duration energy storage technologies. How you bridge that reliability gap and I think understanding these uncertainties, variabilities and tradeoffs in terms of costs and what that might mean for, you know, hydrogen or long-duration storage. I understand we can't perfectly model innovation, including for technologies that might not quite be commercial, yet, but it seems like that's the missing piece here.

So, to the extent you can really dig in a little bit further on the long duration side, I think hydrogen's probably one of the easier ones to model at this point, especially if you can explore the difference in cost assumptions on the energy side, as well as the technology side, I think that will really help to inform this last gap in the scenario. Thank you.

MS. GUTERREZ: Ed Smeloff from Vote Solar.

MR. SMELOFF: Good morning Commissioners. And I want to thank you very much for organizing this workshop. It has been extraordinarily informative and I really appreciate the presentations that each of the panelists here made.

I have sort of two observations I'd like to make. The first is to the extent that we are going to have to retain combustion technologies to be available during those limited events in the winter, the dark doldrums events, we need to think carefully about how that interacts with the natural gas delivery system here, in California.

SB100 actually does call out specifically that the SB100 report does need to address both the impacts on the gas system and the water system. So, it is important that that be in the report.

So, as we think about having, you know, assets that are used, these reserve contingencies that may be used only 10 percent of the time, you also have to think you have this elaborate infrastructure of compressor stations, gas pipelines, gas treatment that will need to serve those power plants for a very short interval of time. So, we need to think of alternative ways, if you're going to rely on those, such as liquid storage at the sites of the plants.

And also, thinking about how this fits in with the issue of resiliency and microgrids, and how we're going to ensure for, you know, adequate reserves even within the microgrids.

The second point I wanted to make was, and I was very impressed with Southern California Edison's presentation about the reduction in energy costs on the average for all consumers as a result of electrification of transportation and buildings. It's a very optimistic scenario.

But if you looked at that carefully, you saw that there was a big distinction between the adopters and the non-adopters, so we do need to pay attention to equity and make sure that there are mechanisms available for those non-adopters so that they are able to participate in the benefits as we move forward on this electrification.

So, again, I want to thank the Commission and the Commissioners for this. And, you know, we're on the right track, but we really need to pay attention to the impacts, both in terms of equity and on other systems. Thank you.

MS. GUTERREZ: And Janice Lin, from CESA. And if there are any other folks in the room that want to make public comments, you can just line up behind one of the mics closest to you, and just introduce yourself at the mic. Thank you.

MS. LIN: Thank you very much for your presentations this morning. My name's Janice Lin. I'm representing the California Energy Storage Alliance.

I have three points I wanted to make. One is just in the spirit of some of the other comments that were made is to make sure that we all maintain an open mind, particularly around energy storage. Energy storage is not just batteries, it's a very diverse asset class with many subtypes, mechanical, chemical, thermal, just to name -- gravitational. Spanning from very large, pumped hydro resources that can be built here in California to behind-the-meter, load-modifying resources such as thermal storage, or chemical storage. And there is so much innovation happening today. So, especially innovation on the long duration thresholds of all of those types, including thermal in front of the meter, electricity in, electricity out.

My second point is that CESA also advocates for hydrogen storage as a means for addressing the multi-day and seasonal needs that have been very accurately identified by some of the speakers here today. And what's neat about hydrogen storage, as it was pointed out, it could be made many different ways, from electrolysis using wind and solar, and also from other resources, other renewable resources such as gasification of biomass. And it can be stored in salt caverns, in modular tubes, and also in the gas pipeline itself.

So, my third point is that one of the ways that we can keep this transition affordable and doable is by finding ways to repurpose existing assets, whether that's repurposing our existing gas pipeline and blending in hydrogen and biogas, as well as repurposing all of those existing thermal generation assets, which can also be run on a blend of biogas, natural gas and hydrogen.

And then, finally, I just want to say that there are opportunities to think about doing this when we think across sectors, but I'll talk about that later this afternoon. Thank you.

MS. GUTERREZ: Thank you, Janice.

Are there any other comments in the room? Okay, seeing none, do we have any on WebEx?

Okay, go ahead, Le-Quyen.

MS. NGUYEN: Yeah, Brian Tarroja, you are now unmuted.

MR. TARROJA: Okay, hello. Can everyone hear me well?

Hi, my name is Brian Tarroja. I'm from the University of California at Irvine, in the Advanced Power Energy Program.

And I wanted to make a couple of comments regarding the modeling and scope to make sure that the modeling framework for SB100 is robust.

The first comment I wanted to make is that the outputs of capacity expansion models are highly sensitive to assumptions embedded in the input data, not only for costs and cost projections, but also in the characteristics and capabilities of the technologies that are included.

So, in the spirit of other comments, we understand that from a technology stand point many of these technologies are evolving to be capable of providing a wider suite of services alongside new and emerging technologies that can address system needs in meeting SB100.

Now, some of these may be difficult to capture with high certainty early on, but it’s very important that the modeling framework for SB100 be flexible enough and be capable of being updated to account for the discovery of these characteristics or the inclusion of these emerging technologies as the modeling and scoping evolves.

And kind of to go off of that, the large amount of moving parts in these types of modeling efforts introduces a lot of uncertainty. So, I really want to highlight the importance of sensitivity analyses, not just for input data, but also for characteristics, and also for constraints that are associated with the tools used in this effort.

And another comment that I wanted to make is that I also think it’s very important for the scoping of these scenarios to assess, at least on a basic level, the non-greenhouse gas emissions effects of the technologies and mix of technologies that are included in SB100 planning.

So, these are things like land use, water use, criteria pollutant emissions, and things that happen in state, but this also should encompass things that happen outside of state, say lifecycle greenhouse gas emissions, material usage, and so on. At least to provide an additional set of metrics that we can use to compare the different scenarios that are coming out of SB100 modeling efforts. Thank you.

MS. NGUYEN: Thank you, Brian.

And that’s it on WebEx.

MS. GUTERREZ: Okay, we are amazingly right on time. So, we will reconvene here at 1:00 p.m. and hear about some of the existing and emerging technologies that will make up the portfolio of the future. Thank you.

(Off the record at 12:01 p.m.)

(On the record at 1:08 p.m.)

MS. GUTERREZ: Okay, if everyone can just have a seat, we will get started with our afternoon portion of the workshop for SB100.

I will introduce Jonah Steinbuck from the California Energy Commission. He is the Manager of the Energy Generation Research Office. And he will be introducing the next panel.

MR. STEINBUCK: Thank you, Aleecia, and good afternoon to everybody. As Aleecia mentioned, I'm Jonah Steinbuck, Manager for the Energy Generation Research Office and very glad to be able to engage in this SB100 conversation with all of you. And I joined the Energy Commission just a few months ago and look forward to working with you towards this clean energy future.

So, we've got two great panels this afternoon. The first one is going to be focused on continued innovations and some technologies associated with our major renewable resources.

And then, the second one will be more on emerging technologies that will also be, you know, contributing to and enabling our clean energy future.

And what we're hoping to do today is really just draw on expertise across a broad range of technology areas, have that inform some of our thinking around SB100 modeling. And then, ultimately, inform our thinking and approaches to implementation more broadly.

So, before getting too deep into the panel, I want to just take a couple minutes to share how the Energy Commission is supporting technology innovation, specifically through the Electric Program Investment Charge, the EPIC program. Many of you are probably familiar with it, but some may not be.

And we are really seeking to catalyze innovation and accelerate achievement of our clean energy goals through EPIC. We award $133 million a year in a broad range of areas, renewable generation, storage, microgrids, electrification, demand flexibility, among others. And it's all oriented towards decarbonization, resiliency, affordability and equity.

We're seeing some great impacts from EPIC. As one example, we've been supporting solar PV tracking. So, Leila Madrone from Sunfolding is here. They're one of our partners. We've been supporting their efforts to improve PV tracking technology, reduce the number of components and cut down some of the costs of installation.

Nevados Engineering is another example that we've been supporting their work on PV trackers on uneven ground, which eliminates the need for land grading and opens up more sites for installation.

Another example from EPIC is the CalSEED program. This supports early stage California clean energy startups and helps bring their concepts and their prototypes to market. And it's one of the easier ways to get involved in the EPIC program. It's got a simple application process and there's smaller, kind of smaller awards that range up to $150,000. And then, if successful, there's an opportunity to apply for follow on funding up to $450,000.

We've invested $8.3 million so far through CalSEED, over the past three years, and that's resulted in $32 million of follow on funding, both public and private. It's also generated 32 patents and 37 different pilot projects.

Another example from the EPIC program is the four innovation clusters that we support across California. The local example is Cyclotron Road, and Tim Latimer from Fervo Energy is a current Fellow there. So, we're providing business support for entrepreneurs, access to labs, investor connections, coaching, et cetera.

And through those clusters we've invested -- I should say, our investments in those clusters have generated a threefold increase in follow on public and private investment and we expect that to only grow.

And then, looking more broadly at EPIC, we've also been kind of analyzing the impact of our funds as like a catalyst for broader public and private investment. And based on 29 startup firms, where we have good, strong data, we've seen a doubling in the amount of investment, public and private, after an EPIC award relative to before, and reaching levels of $1.1 billion collectively in investment with some of these companies.

So, we run a public, transparent process and have a preference for funds spent in California. So, most of our partners are California based. And a very strong emphasis on low income and disadvantaged communities. Thirty-two percent of our demonstration sites are in low income communities and 34 percent are in disadvantaged communities.

And then, I wanted to highlight this new site that we just recently launched. It's called Empower Innovation. And the idea here is to connect and support innovators working to build a hundred percent clean energy future. So, entrepreneurs, funding providers, researchers, businesses and local governments that are looking to deploy new technologies. And it provides access to funding opportunities, resources and upcoming events.

And you can see different -- it's got a broad range of funding opportunities. Bu9t for the CEC ones, you can indicate your interest in it and see who else has indicated an interest, and message with them and explore potential partnerships with others that may be interested in a similar topic. Maybe a demonstration site host or a technology vendor, et cetera.

So, the website is empowerinnovation.net, and encourage you to take a look when you get a chance.

So, with that, I'll turn it over to our panel. Again, this first one is focused on continued innovation and some of our key existing renewable resource areas. So, we'll be discussing some of the state of the market, some of the technology trends, and cost trends and innovations occurring all with the aim of informing this SB100 discussion.

So, our first panelist is Leila Madrone. She's going to be speaking on solar PV. And she's the CEO and co-founder of Sunfolding.

MS. MADRONE: Now can you hear me? Great.

So, I'm going to talk to you about what the next generation of solar infrastructure could look like. But let's first look at what's been happening in the past. I think this is probably a familiar image to most of you. Solar has come down by 300 times over the last 40 years.

But what's really interesting has really been this kind of -- and as it's been coming down, as you'd expect, as you start to get a good return on investment, you start to see installations on the rise.

But it's really these last ten years that have really put us at this new kind of inflexion point for solar. We've actually brought the price down of solar an additional 10X. Those are really hard won, mostly on getting the components at much, much lower cost, especially the solar modules and inverters.

And what that brings us to in terms of inflexion point is a point where in particular cases solar and wind are cheaper than coal. And at the low end, they're sometimes half the price of coal.

And if you look at the power generation mix, as seen for the world -- I didn't have access to those great modeling slides we saw this morning that were just for California. But as expected to see for the world, we're looking at seeing something like 48 percent of the world's resources by 2050 be solar and wind combined.

And as you probably well know, California ranks first. California has 25,000 megawatts installed. The next state has only about a little over 5,000 megawatts installed.

And some nice, kind of California facts here.

First in the U.S., and probably going to be first for quite a while, that's enough solar to power 6.7 million homes. And actually, about 18.7 percent of the state's electricity comes from solar, now, which is really quite spectacular given where it's come over the last ten years.

There's a lot of jobs and businesses that have been generated via solar. And right now, the growth projections are about another additional 15,000 megawatts over the next five years. But as we saw this morning, to meet SB100 that could actually look like another 100,000 megawatts or more by 2045.

So, one of the reasons I think probably the models show that the future mix looks like mostly solar is that we're at a point where solar is cheaper in coal. Well, this is only sometimes true. And it's complicated and it's getting more complicated, especially in California.

And so, if we break it up and see here's one part of where the complications are. All the way on the left here we have the breakdown for residential solar. All on the right, we have utility scale. Those are the really large projects. And the bottom couple bars have to do with those direct components that we've been working on reducing the price of for the last 40 years.

And those top bars represent kind of the rest of the system. The installation, the permitting, the dealing with the land, the civil works, all that's required to actually put a system in place.

And the problem we're seeing now is that with all of this kind of deployment we want to see with solar, we want to make sure that that future return on investment is at least as much as the current or predicted return on investment.

And why this is actually a problem we should be looking at is that project space and the conditions in building solar in California, even with incentives, once you're at 18 percent penetration it's becoming more challenging. The pricing is going down and the sites and the actual projects are getting harder to do.

So, all these new factors in solar, they keep contributing to drive up the fully installed cost, while the prices keep going down, which makes for a worse return on investment, of course.

And so, solar continues to be a viable solution only if innovation continues to drive costs and expand the boundaries of where solar can go. And the reason I say this, is that if we remember from this cost curve, we put a lot of work into getting the component costs down. And those kind of top bars, which are kind of the soft costs, and the land, and the way it gets installed, this is a place where we now have to pay attention because this is the place where things are going to get complicated.

So, I'm now going to talk a little bit about Sunfolding. This is a Sunfolding plant. We are a solar tracker company and, hopefully, this video works. So, solar trackers, if you don't know, they're the machines that move the panels to follow the sun to make the most energy possible.

We are building a new kind of solar tracker. And the way it works is, as you change the air pressure on either side, you change the position. And what's so interesting about doing it this way is that we actually replace dozens of components that are currently in a utility scale power plant with a single part. And we create a solar plant that's much, much simpler and is much more modular and adaptable to different types of land.

And, so, the path of solar in California and other places, the place you had to develop looks like this. They were flat, you could build beautiful, north/south facing rectangles. It was really easy to get your installation to be very optimized.

And this is probably what the future of solar looks like. And I would say that's even what the present of solar looks like, given what we're seeing in the market.

And so, what was really interesting to me from Sunfolding is we've been doing this for almost ten years, and we originally were creating this new kind of pneumatic tracker system to lower the price of the component.

But what we've found once we've got into market, we've now deployed over 100 megawatts, is that the reason that customers want to use us the most is because they can now utilize land better. So, by having a really modular system you can fill in all the nooks and crannies of the land.

And another place that was alluded to before is when you have undulating terrain. Even if you have some land -- so, usually, what you do when you're building a bit solar site is you basically just level the land. If there's any kind of undulations, you just grade the whole thing, you get rid of the whole thing and you make this nice flat piece of land.

We're finding that it is a lot more cost effective and a lot more environmentally advantageous to instead have plants that follow the land. So, instead of creating -- making the land so that it fits into the shape of the plant you want to build, you have the plant follow the land.

And so, I would say that was really just touching on one piece of it that we've seen from deploying Sunfolding. But we've seen that really the places that we're starting to see the struggling points and the complications are really around these three kind of topics.

So, first is land usage. We want to get more capacity and higher efficiency, and we want to expand the boundaries of solar. So, you want to be able to develop every single site with limited extra cost and limited kind of environmental upset.

On the construction side, I don't really have time to talk too much about this, but because we've been able to replace dozens of components with a single part, just by changing the underlying machine we actually can install a solar plant two to three times faster. And that's important both from a cost perspective, as well as wanting to deploy a lot more solar, a lot faster.

And then, on the last piece, solar is actually really new to the grid. I don't think anyone knows how much it's going to cost to maintain it, yet. And so, a lot of that needs to be put into both putting in technology that has reduced long-term operating cost, and thinking about how we're going to deal with these kind of long-term, sustaining O&M challenges that we haven't even really started looking at, yet.

That's all I have for now, thank you.

(Applause)

MR. STEINBUCK: Thanks, Leila. That was very efficient, too, so we're in good shape time wise.

The next speaker is Johnny Casana. He's the Senior Manager for U.S. Political and Regulatory Affairs at Pattern Energy Group.

So, over to you, Johnny.

MR. CASANA: Thank you. And I apologize, I don't have any videos in mine. That was so cool. You'll just have to take me as I come.

Yeah, we're Pattern Energy. We're a San Francisco based wind, solar, storage, and transmission developer. An American company. We're one of the largest suppliers of clean power to the State of California. We have a global footprint. But wind is what we really have done a lot of, mostly, so they asked me to talk about wind.

I put this slide up as a sort of looking at the sort of long-term national perspectives. She had, that was great, the Bloomberg and the IA slide. I loved that one.

This takes some of that same research and pins it against an NREL projection of what the U.S. probably needs in terms of wind and solar deployment to get to Paris targets.

And so, this orange bucket, it looks mustard yellow here. On my slide it was orange, so sorry about that.

So, this is the projection from Bloomberg with current policies and economics for utility scale solar. It goes up pretty steadily over the next couple of decades, which is great.

This yellow one up here is rooftop or distributed installations. It also increased pretty good, which is great.

This gray line in there, that's offshore wind which, you know, more of than we had before, and Adam's going to talk about that.

This blue line here is national existing policies for land based wind, which is pretty flat in aggregate. And that includes a lot of retirements and replacements over time, but it's pretty flat.

And then, these dots up here are what NREL predicts for those four segments we'll need to achieve climate targets as a country.

And utility scale solar is pretty much on track.

There's a gap. Rooftop solar is a little over-subscribed. We need some on offshore. But the big gap for the U.S., in terms of, you know, with existing and projected technologies how are we going to get to our climate targets, assuming we stay in the Paris Accord. We'll see. A big gap for land based wind, 375 gigawatts, you know.

So, this is sort of like a starting point of thinking what does the future look like for these two great technologies that have come down so much in cost and have really entered the mainstream, but our existing policies are only really working for one of them.

So, what does that mean for us, as a country? I also, sometimes put up -- this is a slide that Brattle did a couple years ago. You know, when we talk about utility scale grids across the country and across the world, we often get questions about do we even need wires and utility scale anything at all.

And this is a Brattle study that looks at -- they're essentially making the case, which has been made lots of other places, that to deal with climate with the tools that we have, and the timeline that we need to do it, it's a kind of two-step path where you clean the grid and you electrify everything. So, decarbonize electricity, then make buildings and transportation as much as you can electrified for the end use powers. And I think that shows up in the PATHWAY study. That shows up in a lot of the work that California is doing.

But I thought this was -- this is an interesting, sort of like not many people have done this, but they put the -- they modeled distributed solar on half of the houses in America and it got 2 percent of the way to climate goals. And then, the modeled rooftop solar on 100 percent of houses in America, or roofs in America, and they got 9 percent of the way to climate goals.

So, it's like it's a very important -- we often think of it as a very important part of the puzzle, but by no means anywhere close to solving the challenges that we have ahead of us in the next few decades.

Decarbonize the electric sector. And this is only one study. It's not gospel, but directionally I think it's interesting.

Thirty-six percent of the way to that, you know, carbon goal by 2050. And then, if you electrify buildings and transportation you get a lot closer, within striking distance if maybe we, I don't know, eat one less hamburger a week, or something. I don't know.

But this speaks to the need to deal with that big gap in the wind side in terms of what the next couple of decades look like in policy.

Why are we doing so great, you know, the Lazard I think does a great, and this is where these numbers come from talking about the levelized cost of energy for wind and solar has come down dramatically. Leila put up some great slides from Lazard. This is the wind comparison to it.

They just came up with, and these are unsubsidized, so these are sort of calculated U.S. costs without the PTC or the ITC. They just last, a couple of weeks ago, put out their new numbers. And the PTC wind was down to $11 a megawatt hour, which is just like shocking and stunning, and these are super high capacity. Factoring in, you know, 50, 60 percent NCF. Down to -- you know, when you're talking about one cent power, a lot of things that didn't used to seem physical, or practical, or politically viable start to make a lot of sense.

And they are both now cheaper than the levelized cost of new gas and new coal projections from a number of different groups, including Bloomberg put about 10 years out, maybe early 2030s it starts to be cheaper to build new wind and solar at the utility scale than to even continue to operate existing gas, let alone coal.

And so, then, that brings into a lot of question about what is the investment prospect for a 40 or a 50 year gas plant at this point, if 10 or 15 years out it's not going to be economic to run? And that's a real challenge. And that's something that, you know, we'll have to all sort of look at. But declining cost of wind and solar are important.

I put DG solar up there. It's, you know, again, a very important part of the solution, but quite expensive compared to the utility scale parts of the team.

And then, this is another study that came out of Austin last year, which is the places in the country where wind is the cheapest, where solar is the cheapest, and where gas is the cheapest. And practically nowhere is anything else cheaper.

So, these are just -- these are some of the things that are driving the economics on the wind side. These are those turbines you see out in the Tehachapi pass. And then, if you drive up to Las Vegas you'll see along the road. These are what they'll look like. You know, they're much bigger. As with refrigerators, and cell phones, and VCRs and personal laptops, the more we build something as a society, the better we get. This is a real tech sector revolution. You know, the technology running the turbines, the gears themselves, the size of the blades, and the ability to build them with a deep and vast human resource, you know, pool all over the world has really driven the cost down.

And there's this cycle, there's this, you know, virtuous cycle of cost reductions drive to more installations, which makes policy support much easier, which helps drive down the cost through technology innovation, which perpetuates that cycle. And we've seen a lot of that. California was really at the forefront of that.

But unlike on the solar side, when you talk about 25 gigawatts leading the world, ten years ago California was leading the country in wind installations, and now we've fallen short behind Texas, by a -- I think we've only got about 6 or 7 gigawatts here and Texas has 20 some odd. So, they've vastly outpaced us and other states are outpacing us year after year. We have really had very much new wind serving California recently. And considering how cheap it is and how well it pairs with solar, that feels like a challenge that can be surmounted and probably will as we get into meeting our RPS and our GHG reductions.

The other sort of great thing that we like to think about is, you know, the U.S. is divided up into -- you guys are all nerds, you know this, but anyway.

Nerds are cool these days, all right, fine.

But the U.S. is divided up into three different grids and most of the customers in our Western Grid have followed California's leadership in passing their own very ambitious 100 percent clean energy laws, or very high renewable portfolio standards. Or, the utilities in those states, on their own accord, have suggested that they're going to pursue a deep decarbonization.

And that has to do with how cheap everything has become. Again, you're talking about one and two cent power, and just lots of it. It's really an appealing thing to start leaning into and these policies started to be easier to pass.

The thing I love is that, you know, 14 months ago there were no 100 percent clean energy laws in the west. I don't think in the -- maybe Hawaii. But on the continental U.S. there were none.

And in just the past, you know, ten months or so there have been five states, including California, have passed that. So, that's the majority of customers in the west. And then, you've got these little cities and municipalities.

I'm putting this up because when we think about the value that wind can bring to the climate challenge and to meeting all of these ambitious goals, we think about the west as an integrated market. And that's pretty important for sourcing the best wind to the solar in this broad economic system.

There's a study -- there's just a lot of studies, so I don't know, we'll do Q&A later. But a study that is just coming out this month on what it all means with those various western states to have such ambitious targets. This is not even, necessarily, meeting climate goals, but just meeting the policies that are on the books. And it's similar, around 9 gigawatts per year of utility scale wind and solar needed for 15 years in a row, starting in the mid-2020s.

And it's just this huge, huge need that California really triggered and is really a big part of as the largest customer in the west. But there's a lot of neighbors that have a lot of the same ambitions and our electric system is integrated into theirs. And I think none of these states are going to be able to achieve their goals on their own. So, we see wind playing a really big part in meeting all of these goals collectively. And the studies, at least, seem to support that.

I put this slide up. This is from NREL. And they did some really great work on, you know, transmission studies. This maps out the three different grids, East, West and Texas. And then, they put where the best solar resources are in the country and where the best wind resources are in the country, and then these red dots are where the load centers are. And this is just one of the problems of living in a very, very, very big space where they kind of built the grids in from the coast, and stopped building them right in the place where it's -- when you're talking about the one cent wind power, that's where it's coming from.

And so, you know, we think a lot about how to get this kind of super high quality wind to pair with this kind of super high quality solar, and serve all of these 11 states, most of whom are aligned with us here in California on a demand, and an excitement over adding renewables to the mix.

This is, you know, another map of, the NREL map of where it's windy. I bring this up because again, you know, this is sort of the -- this is the contour of the electric grid that we've got and utility scale wind and solar, so the needs that we have in the near term to get to our climate goals and decarbonize society.

And, you know, our company's really focused on this kind of hot spot here. And here's -- yeah, so this is something that we've done a lot of. In the past five years or so, our company's wind from New Mexico has been just shy of about 20 percent of the new renewables that have been contracted here in California.

About half of the stuff that we have that’s operating or contracted to serve the state is in state, and about half is out of state. And these are all wind, financed in conjunction with new transmission, new merchant transmission that never shows up in any California regulatory proceeding because it’s built entirely outside of California. So, these won’t show up in the interconnection queue, they won’t show up in the California transmission planning process. They won’t show up in the sort of PUC’s identified these are the transmission lines that should be built. These are new build transmission lines to connect the wind to the existing grid, at which point there’s capacity that we purchase to get across the different balancing authorities to dynamically schedule into California, serving IOUs, and CCAs, and municipals with bucket one RPS power that sort of meets all of the rules of the policy.

That’s something that, you know, we know a lot about a pattern, but it sometimes doesn’t always register because there’s a thought that out-of-state power doesn’t count somehow, or shouldn’t be though about somehow.

But it’s very, very competitive in all the solicitations that have happened in the past five years here, in the state.

Next year, we’re about to start construction on our next big power line, Western Spirit, which will bring about a gigawatt of new wind online, mostly contracted to California off takers. That’s passed all of the permits that it needs to. It has all of its state and regulatory approvals. And it’s going to be acquired by an IOU out there.

And then, after that we’re the anchor customer for the Sun Sea Line, which is 2 to 3 additional gigawatts of wind from this very, very high capacity factor place.

And that is relevant. And one of the reasons -- I know, I’m -- one of the reasons it’s so relevant is because the PUC, when they did their studies for the ISO on different scenarios to meet our GHG standards, scenarios that they ran with access to regional wind, through new build transmission, like the stuff they’re developing, save customers, you know, up to half a billion dollars per year.

Maya’s in the back there from TNC, The Nature Conservancy. And they did a study that’s sort of not looking at necessarily the costs, but looking at the land impacts and how to build out like needs for California, with the most sensitivity to conservation lands. And it aligns with this thing. It's not only amazing for ratepayers, it's some of the most responsible environmental siting to meet these needs.

And, anyway, he's standing up there. That's probably a cue that it's time to go. But, you know, it's a big, cheap part of a big solution that we need and we're here to help.

(Applause)

MR. STEINBUCK: Thanks very much, Johnny. And apologize that I cut you a little short.

We're going to continue the conversation with Adam Stern here, who may continue the wind theme, but an untapped aspect of it. So, he's the Executive Director of Offshore Wind California.

MR. STERN: Okay, thank you. Thank you, Jonah, thank you, Commissioners, and thank you to the audience for being here.

We're a new trade group that launched just last month, here in San Francisco. We represent, now, seven companies, including some global heavyweights such as Orsted and Equinor, who are working on offshore wind around the world and now have come to California to help develop the opportunity here.

I want to just start briefly with a mention about some of the attributes about offshore wind that are particularly attractive, that's been referenced earlier in the discussion.

The blue line in the middle is -- basically demonstrates the steady and consistent flow of offshore wind, which is a great complement to the solar patterns that are prevalent here in the state and that the discussion today has helped highlight one of the challenges. So, offshore wind can be a great synergistic addition to the energy supply in this state.

I want to describe, as well, the technical resource capacity. This is from an NREL study that was done a couple of years ago. Looked at the full gross potential and then trimmed it down based on a variety of criteria, including water depth, and wind speed. And concluded that there are 112 gigawatts of technical capacity in California.

And then, moving quickly to the practical, these are three call areas that have been identified by the Interior Department's Bureau of Ocean Energy Management. They are slated to have auctions in the next year to 18 months, at least based on the reports we get from BOEM. So, there's Humboldt Bay in the north, Morrow Bay and Diablo Canyon in the south. And these are all substantial areas that could generate a significant amount of offshore wind for California.

And this slide begins to define the scope of those. The lower three are the three call areas I mentioned, but this only a portion of what's possible because there are a couple of other areas further to the north, in Cape Mendocino and Del Norte, which have an even larger amount of resource.

And the key technology advance that California is positioned to take advantage of is that most of the offshore projects around the world currently are using what's called fixed bottom technology. They actually have a foundation that connects with the bottom of the ocean.

But there's a new, rapidly developing technology where they have floating platforms. And these are spreading across the world. And here's a series of about 15 projects that are in various stages of development. Some actually are already operating. But from Norway, to Japan, to France, and Scotland, and these are both growing size and they're dramatically dropping in cost. And I share this because sometimes the idea of floating technology has been seen as something way in the future, but it's actually happening right now and there are a lot of significant projects that are underway in different parts of the world, which California is going to take advantage of from the lessons that are learned from these projects.

And, similarly, because of these advances, the cost of floating offshore wind is dropping dramatically. These are, again, studies that NREL did, and show the decline in costs. And I just want to quickly get this right, going from $175 per megawatt hour in 2018 to $70 per megawatt hour in 2030.

This is a rapidly changing field. And just at a conference a couple of weeks ago in Boston, one saw reports of additional advances that haven't even been fully disclosed in charts like this.

But one example I'll just mention, there's a new NREL study about offshore wind in Oregon that shows $52 per megawatt hour in 2032. So, I'm confident, based on the data, that California is going to be positioned to take advantage of not just the advances in technology, but the decline in costs.

And here are some estimates that have been made about some of the areas that I highlighted that are within the Interior Department's call areas.

There are a series of barriers that we need to work to, to overcome, to take advantage of this resource. The first is transmission capacity. The load is not ideally aligned with where the supply is. And so, this is something that we're going to need to work on as a state. It's probably going to require some significant investments to overcome that.

There are certain examples, though, where there is good transmission. And one I'll just highlight, Diablo Canyon, right along the same latitude as the Diablo Canyon nuclear power plant that is due to be retired in about six years. And when that happens, that infrastructure that's there could easily be adapted for use for offshore wind.

Secondly, there are some overlaps of the areas that have been identified for offshore wind with current and potentially future activities of the Department of Defense, specifically the Navy. And there are discussions underway between the Navy and the Interior Department to try to work out the conflicts and, ideally, reach some common agreement on the areas that would be allowed for offshore wind development.

And then, the decentralized nature of our energy procurement in California today creates a new challenge for us. Because with utilities, CCAs, ESPs there's going to need to be some type of collaboration in order to procure the power at the scale that's going to be required to make offshore wind economic. And that's something that, again, I think is going to require a lot of state collaboration to achieve.

And, finally, the permitting, I've heard it said, though I haven't seen the list, that there are upwards of 25 agencies in the State of California that may have some interest in offshore wind siting, and other related issues.

It would be a huge boost to the future of this industry if the state, perhaps with leadership from the Energy Commission, could define the permitting roadmap. Ideally, develop a program in which some of the permitting procedures happen in parallel, rather than in sequence, and that would be a great signal to the industry that California is thinking through how to do this permitting process.

I don't mean to in any way diminish the importance of the permitting, because there are a lot of issues around fisheries, and other ocean users that need to be accommodated. But let's see if we can do this in an efficient way so that these resources can be taken advantage of as soon as possible.

Thank you.

(Applause)

MR. STEINBUCK: Thanks very much, Adam.

Our next speaker is Tim Latimer. He'll be speaking on geothermal. And he's the co-founder and CEO of Fervo Energy.

MR. LATIMER: Thank you, Jonah. I'm excited to be here. I think this is definitely a very interesting day in terms of both the magnitude of the issue, but then also listening to how many different options we have in the toolkit to solve it. So, excited to make a contribution on the status of geothermal here.

So, Fervo Energy is a geothermal development company. We're currently based in Berkeley, California. Part of the CEC funded Cyclotron Road program there, so already, you know, a beneficiary of the innovation ecosystem that the CEC's built.

And we were founded in 2017, out of Stanford University, with an idea of using advanced computational models and targeted horizontal drilling to make geothermal both more predictable and cost effective. And so, we're supported through Cyclotron Road, backed by Breakthrough Energy Ventures, from the venture capital side, and have gotten other grant awards from organizations like RPE.

I'm excited to talk about geothermal. I think it's somewhat unique in terms of energy resources in California, in the sense that it's both old and new. Old in the sense that is has been really a renewable energy workhorse in the state for decades. Still, today, it's 5 percent of generation, which makes a very meaningful contribution to the low carbon grid here in California. But it has not grown much and we really need to see different technology or different policies to expand that.

So, given the theme of today on grid modeling and options, I'm going to talk a little bit about cost and load profile, and things.

And the first one I want to talk about here is a misconception that -- about the load profile of geothermal. So, geothermal is often referred to as a base load resource. In the continental United States and in California it is primarily a base load resource. But people take that to mean that it can only be a base load resource. And if you go around the world to different grids, where geothermal makes up a more meaningful contribution, they ramp it all the time. And it's not really a technology question, it's something that's done quite regularly.

And so, I just wanted to take an example here, during the shoulder season in Kenya, which gets over 50 percent of its electricity from geothermal energy, it's very common to ramp throughout the daily cycle. So, here's a plant that goes through the evening hours of low demand at 80 megawatts, and then ramps up to 140 megawatts to meet the daytime load.

And so, geothermal, like I said, if there’s one takeaway from this is that geothermal can be flexible in markets where it makes sense to do that or it’s incentivized to do that it can certainly be part of that picture.

Geothermal has also been -- just since we’re talking about barriers, I thought it would be illustrative to discuss what has been successful in Kenya, where geothermal has grown by a factor of ten this decade, to be more than 50 percent of the generation profile. And there’s really been three things that have been very successful there from a policy stand point.

One is a clear tariff structure that’s long term. Geothermal development cycles are three to five years, or longer. You really need to understand what you’re doing early in the investment cycle to bring a project online. So, having something that puts that long-term certainty makes a really big difference in the cost of capital and the development timelines.

And then, they’ve also been very effective at using public/private partnerships and innovative risk financing. So, the most costly and risky part of geothermal development is during the exploration period. And a facility they have, called the East Africa Risk Mitigation Facility, puts matching funds for early stage projects that can be anywhere in the development cycle, including confirmation drilling that gets the projects through the riskiest phase.

And once a resource is proven out, they've been able to unlock hundreds of millions of dollars of private financing to pick up projects and go forward. So, I think there's a couple lessons that we can learn here.

Now, let's back around the world to California. And like I talked about before, it's been a big -- geothermal's been a big part of the mix, but over the last 20 years it's been in decline. So, about a 14 percent decrease since the turn of the century.

And if you look at -- you know, firm capacity was talked about a lot today. It's clearly something on the top of people's mind. And if you look at the preferred system portfolio that came out of the most recent IRP process, it calls for more than a doubling of geothermal generation by 2030.

This is doable, but it clearly is going to require something different than what we've been doing in the last 20 years. And so, I wanted to talk a little bit about that.

And it's not an issue related to resource. So, the current effective capacity of geothermal in California is about 1,700 megawatts. We need to roughly double that if we're going to hit the reference system portfolio in the IRP to around 3,400 megawatts.

And what you can see from resource assessments that have been in the state, that doesn't even scratch the surface of what they call the conventional geothermal resource, which is at least 14,000 megawatts. And it doesn't even get into advanced potential from technologies like enhanced geothermal systems, where there's a lot more to go.

And so, it really is not a question of resource availability. We just have a lot more that we could develop here in California.

And so, to talk a little bit about the current cost situation, throughout the 2010s, the average strike price for a PPA of geothermal in the U.S. was $84 a megawatt hour, but it's been trending down in recent years. So, the two most recent geothermal contracts signed in California were at $68 and $76 a megawatt hour.

And one thing to keep in mind is since 2015, geothermal has not had access to the 30 percent ITC, so these numbers are much inflated relative to what it would be if you had other structures.

And so, if you remember the last slide, thinking about resource potential, there's a lot of conventional resource and there's a lot of enhanced geothermal systems resource as well.

And so, I think this chart from NREL, from the annual technology baseline is fairly interesting because what it shows is that of that conventional resource, there's actually a lot of it that would be in the money today, and that we can develop. And that's why we're seeing geothermal grow by a few hundred megawatts over the last few years, and will continue to do so.

But also, in the right technology scenarios, where we properly incentivize R&D, you see the costs falling for other types of resources as well. So, whenever you reach that 2030 timeline, even the enhanced geothermal systems resource, and the deeper resources, and the lower temperature resources could quite possibly be in the money. And that's where you get to tens of thousands of megawatts of potential.

And there's major technology development underway. The figure from the left is from the GeoVision Study, which was a multi-year study released by the Department of Energy this year, that outlined a path to get to 60 gigawatts of geothermal in the U.S. by 2050, and the technologies that we need to do there.

And there's also exciting things going on. The FORGE Initiative is a $140 million geothermal test bed located in Utah, that's the largest ever field demonstration of geothermal to date. So, there's -- so, that is going to bring a lot of technologies to the field demonstration level that have never been tried before.

There's also technology transfer opportunities. Anybody familiar with the U.S. energy markets can tell you that the advent of unconventional oil and gas has been one of the biggest surprises and technology stories of the last 20 years. And a lot of the technologies, like directional drilling that made oil and gas unconventional and cost effective, have strong applications in geothermal. So, the technology transfer could make a big deal.

And another thing that's big both from the federal level and in California today is lithium and other strategy mineral coproduction. So, there's organizations and initiatives going on where you can actually domestically mine lithium straight from the geothermal brine that's produced.

And so, not only can you produce clean power around the clock, but you can get a strategic resource like lithium, which is key to our clean energy future, directly on site.

I'll talk a little bit about Fervo. The key innovation we're bringing is drilling down and drilling horizontally at depth, which leads to a much more predictable development cycle and leads to flow rates that are as much as four times higher than traditional geothermal, which we've shown through our modeling capabilities, and other evaluation work, and really reduce the risk profile of geothermal development. And create resources in different geologies, and with a lot more predictability than have been done before.

In terms of things we can do right here in California, the first and most important thing is field level drilling and reservoir research. The other things that are cool about geothermal only work if we get the cost down enough for drilling. And the only, really, way to innovate in the space is through things at the field level. So, there's only so much you can do before you actually go out and drill new wells, and test new technologies at the field.

I think there also needs to be more work in terms of flexibility studies and market design. Geothermal can be flexible, but it needs to have the right markets to be able to do it. And scaling up some of the promising technologies around mineral production is quite interesting.

So, I think there's a chance to -- for geothermal to make a much larger contribution by 2030 than it is today. It's a really unique resource that has a lot of qualities to it.

And in terms of things that are conventional resources that are ready to develop, the estimate of what's at the right depth and cost picture is pretty in line with what comes out of the CPUC's preferred system portfolio, where I think 2,000 new megawatts by 2030 is a very reasonable target.

And then, as we bring costs down for more advanced geothermal systems, I think from 2030 and beyond there's a lot more resources we can access, so that there's a much larger potential for geothermal in the state, getting up to 10,000 megawatts or more.

Thank you for your time.

(Applause)

MR. STEINBUCK: Thank you, Tim.

Our final speaker is Dr. Stephen Kaffka. He's going to be speaking on biomass and biofuels. He's the Director of the California Biomass Collaborative at UC Davis.

DR. KAFFKA: Thank you. This is a complicated topic. And biomass, when we use it and think about it, it's hard to isolate a simple power production from fuel production, and even from bioproduct production.

So, I'm going to try to provide an overview of all those various ways in which biomass might be used in California. I'm not sure which side to look at anymore. So, you'll maybe get a crick in your neck, we might go on the other side.

This is a figure from a recent CARB meeting on neutrality, and these are quotes from Dr. Nathan Lewis, a Caltech scientist. He mentions that there's some technically difficult energy sources that have to be addressed and they include both aviation, and long-distance transport, industrial materials, and highly reliable electricity, which we're obviously seeing problems with currently.

He mentioned that biofuels are one potential for some of these. It's not the only one. There are other synthetic processes, but they're not yet developed. And to achieve all of these goods we need systems that have robust storage and have flexibility in generation.

So, this is the tricky biomass. It's an interesting slide. The things that are going to be more difficult to deal with are the things like long-distance transportation and aviation. Carbon and energy that goes into iron, and steel, and cement. And then, load following electricity. And biomass has a role in all of these places, potentially.

This is an interesting figure from a recent study that shows -- that mapped solar and wind, I think, resources for California. And there are areas during the year, periods of time during the year where there are deficiencies, typically, from a climate perspective. Now, some of those might be addressed through the very innovative approaches that we've been hearing of today, but they're real and they represent a significant challenge that we've been hearing about.

So, I want to talk a little bit broadly about, first, biomass resources in California from the major sources, and then a little bit about transformation pathways and opportunities, and how they might be integrated. And talk, lastly, about no regret uses for biomass.

This is a figure that comes from the Collaborative. It's an older figure and it indicates that we have resources, fairly abundant, gross supplies of biomass from both AG, forestry, and urban sources. We can -- you know, have done these kinds of projections on a gross and technically available basis, but none of these have necessarily dollar signs associated with them. They're just basically what are the resources.

More recently, these maps were produced using some of our same data by a group, for a recent CEC report. And you can see, actually, that the resources are distributed very differently. Obviously, the AG resources are in the Central Valley. The forest resources are in the Sierra, Cascades, the Siskiyou's and the Coastal Regions. And the urban biomass is largely where the people are in Northern and Southern California.

There are objections to the use of biomass. Some of the utilities regard biopower as expensive, polluting, and actually no longer needed in the future. There's some discussion about whether biomass is or may not be carbon neutral. We know that accounting for biomass is very difficult. And perhaps some people argue it's compromised by unavoidable epistemic error.

And there's some people who worry about biofuels competing with food production, for example, and emitting, leading to secondary pollution.

Some of these criticisms are fair, but I think that there are prudent and abundant, and potential uses in California, particularly that avoid all these criticisms.

Now, biomass is complicated. You have complications on production, collection, processing storage. There are diverse transformation pathways and technologies within those pathways. And there are numerous products that come from biomass. There's certainly energy, both in the form of heat and electricity. There's various kinds of fuels and there's various kinds of products.

So, all these pathways are potential uses and some of them actually are co-combined, together, in certain processes.

Let's first talk about the biochemical one, which is anaerobic digestion. Basically, it's the kind of fermentation that takes place in a cow's rumen. You have usually high moisture materials and you produce methane and some other gases, and that methane can have a number of uses.

This is a net recent estimated. A colleague, Rob Williams, has done this for the Collaborative that estimates biogas potentials from dairy manure, poultry manure, landfill gas, wastewater treatment plants, and municipal solid waste. Those are all sources that can lead to new renewable natural gas supplies.

I'm not going to stick on these slides because I have a lot of material to cover, but they'll be in the presentation and you can look at it. And you can see that there's a certain judgment call about how much of each resource, for example, is likely to be developed.

Now, let's first talk about the thing that most people think is really -- don't have any issues with, and that is the use of urban residual resources. And you can see this is a system, this is the location of L.A., in the L.A. region where you see landfills and wastewater treatment facilities.

If you want to know one place with a lot of biomass, it's Los Angeles. There's a lot of biomass in Los Angeles. It's biomass of this type. It's recycled carbon materials. Green materials from yard trimmings, foods, old construction and demolition lumber, paper and cardboard. A large portion of what is basically tossed away by urban households is organic and has potential energy uses.

This is from a study we did for the Energy Commission a few years ago, of the L.A. region. And you can see various locations where you have MRFs, where biomass is already collected at cost. And there's actually quite a large energy potential embodied in the biomass in that region, from those materials.

Again, it's a little hard to see in the graphs here, but you can look at it later.

Just, for example, a really stellar project that has been developed is CR&R's. It's an Inland Empire located waste management company that is now collecting yard waste and food waste, is digesting them anaerobically. They're producing renewable natural gas that powers their collection vehicles. They have an injection point for Southern California Gas, where that surplus biogas can be injected into the pipeline for users. And they're making compost out of the residual materials. And now, they've recently developed a residual carbon feedstock that's going into cement manufacture.

So, you really have an example of a circular economy, with a number of pathways and products that are coming out of the biomass resource use.

However, it's difficult to develop these projects and partly because of policy. And I have to actually mention this just briefly. Other jurisdictions, the U.S. as a whole, USEPA, and certainly Europe include waste energy recovery as part of their waste management, but California does not. And that's a function of statute in California.

So, there are actually certain barriers to the full use of some of these materials in statute. Those things make it difficult to generate gasification projects, for example, because of restrictions on emissions particularly from gasification projects.

And we don't have a performance base for energy recovery from waste, like we do the low carbon fuel standard. I can't really talk too much more about that. That's a talk in all of itself, but I want to mention that they're there and they're barriers.

Now, there's lots of thermal technologies. We have a traditional combustion system, which I'll mention in a minute, and there are gasification pyrolysis technologies, which are also possible from biomass and which have, I think, a role in the potential future.

This is an existing biomass energy facility. The state built a large number of them during the '70s and '80s and they're located all around the state. Currently, there are almost 50 that were built, but only 23 are operating and 10 are idle, but are still operational and could be brought back on.

What do they use? They use various AG residues, like old orchards, and vineyard prunings and old trees. They use food processing residues, bits and nuts, and so on. They use clean urban wood and some of them use forest residues.

Now, the interesting things is that these systems, one of the justifications is that they were first built to reduce pollution from open burning and other disposal pathways for these materials.

This is a summary of the biopower facilities in California and gives an idea of their megawatt capacities. Actually, I have 27 there and now the number's down to 23. So, this is a little bit out of date just in this last year. There's a lot of turnover in this industry at the moment. But it gives an idea of what the current capacity is and what their sources are.

This is the traditional technology associated with biomass energy facilities. It's a rank and cycle boiler that basically burns biomass, creates stem and turns a generator. You can see there's different types of technologies that have different efficiency bases that are already embedded. They were built for a little bit between two and three thousand dollars per kilowatt originally, and now those costs are higher. They have a range of around 20 to 25 percent efficiency and so on.

This is the permitted emissions from 33 California solid fuel bio energy facilities. The carbon monoxide, you can see they range quite a bit, especially for CO, but these are taken from the permits from those facilities and it gives you an idea of what those criteria pollutant emissions are. There's some emissions associated with combustion, certainly.

However, the emissions from combustion in these controlled facility are significantly less than the emissions from open burning and, certainly, from forest fires. You can see that there's been an increase in recent years, with the closure of some of the biomass facilities in the Central Valley, of opening burning of orchard residues.

And these are some of the criteria pollutant emissions that occur from open burning emissions. This is on the website. We have a report that's going to publish this table very soon. And, in fact, they're quite significant from open burning and from forest fires.

And the biomass facilities may reduce these emissions by up to 98 percent. So, they're certainly not pollution free, but they're certainly pollution minimizing.

Now, here's another interesting way in which they are important. So, the almond industry did a lifecycle assessment of how much carbon is associated with an individual almond or with producing almonds in California. And one of the reasons why it looks like almond production is very energy efficient is because when the trees are taken out and removed, energy is recovered from them. If you take that away, the lifecycle emissions from almond production and other tree production in California go up. That means that reverses some of the goals for the state's program on reducing AG emissions.

And it's actually we're facing a larger and rapidly increasing supply. There's a lot of old almond trees sitting around in the state that were planted years ago, and need to be removed and replanted, and tossed out on the burn pile. So, they're aging out and need to be replaced, just like old folks like me. So, the amount available is expected to increase. So, this problem is actually going to increase in scale.

Now, I just wanted to mention, while we're talking about combustion, that combustion resources are a very common pathway in Europe and that a lot of European countries co-fire biomass with their traditional coal resources. They use waste recovery, which is another biomass source, for their energy program. And they use -- they still have large amounts of recycling and composting going on.

So, here's a very nice picture from the IEA Bioenergy Report from 2017, which looks at multiple uses for combined heat and power operations. This is from Stockholm. Not only is the biomass used for energy, but then heat is recovered and transferred through water, and hot water into those systems. Europeans regard properly sourced biomass as carbon neutral.

And another one of the approaches that IEA Bioenergy is pursuing is the use of biomass energy as a peaking supply. In other words, to help meet deficiencies in other renewables. And they're thinking about pricing it accordingly as a peaking supply. It helps overcome some of the price disadvantages, potentially, of biomass under their conditions.

Now, I want to talk a little bit about advanced thermal pathways, just to make sure we include them, because these are potentially the future for the use of biomass, at least for a number of uses. They're characterized by these high temperature and high rates conversion. It can convert almost all the biomass to energy, or power, or fuel produce, and it prefers the drier feedstocks. So, this is basically the kind of products that come from thermal gasification. You get carbon monoxide, hydrogen and other products. You can make methane from it. You can create hydrogen from it. You can create heat and power from it. And you can create anything. Once you get producer gas, you can make a lot of different products.

There's different kinds of combinations for these thermal chemical pathways. One's a gas fire to a gas turbine. You can then also add to that heat recovery. You can use biomass as part of a co-firing or as a standalone integrated gasifier. You can add fuel cells. We don't have time to talk about them all. I just want to -- these were all summarized in a presentation to the Energy Commission, the data I'll show you some of now, mostly created by Rob Williams back in 2014, for a report.

This is the levelized cost from a biogas -- biomass integrated gas fired combined cycle system, estimated. There's both installed cost estimates and levelized cost estimates. These are based on dollars per kilowatt hour. We don't all always use the same units, unfortunately. But, again, there's economies of scale. This is all from the literature and little bit of modeling projection.

Now, in this presentation that I'm talking about, I'll have some supplementary material that covers all the other kinds of cost curves for gas fires, but we don't have time for that today.

And this is a levelized cost summary from that same study that compares various technologies, like MSW from anaerobic digestion with gasification, which exists with dairy digester biogas, and with potential new systems, which are the red bars, for some of these more advanced thermal chemical techniques. And you can see that some of them are actually reasonably within the price range of other biomass systems.

Now, here's another thing that I wanted to mention that a couple of years there was a meeting about this little, tiny insect called the polyphagous shot hole borer. It's an invasive species from Sri Lanka and it's invaded Southern California. It's killing sycamores, it's killing oaks. It's killing all kinds of shade trees and it might explode in Southern California. And the only thing you can do is to take those trees out. But you can't ship them because the insects spread in ships. You have to grind them. There is no disposal pathway for this potential increase in wood in Southern California. And so, gasification might be a perfect outlet or end product for this. We hope that this doesn't happen and we hope it doesn't spread. We hope it especially doesn't spread to the rest of the state.

But this is the point, the point I want to make is that when you're talking about resiliency on a large sense, these kinds of facilities can have a great role.

Now, there are not too many large-scale gasification systems, but we just came across one called National Carbon Technologies, which is built to scale in Michigan. And this gasification system is primarily emphasizing bioproducts, but also makes energy. So, they have very interesting bioproducts. So, they're making metallurgical carbon, activated carbon, energy carbon which can be used to substitute for coal, and biochar. And all those products have multiple uses.

So, when we're thinking about use of biomass these products, and energy products, are also integrally connected.

I'm going to go quickly over forest biomass. Now, we all know that our forest fire problem is horrendous. As you can see in this picture from the Camp Fire last year, you can't quite see me. I'm under there somewhere. I'm under that plume. A lot of us that lived in the Sacramento area were under that plume.

So, you have health effects as well. And it's these kinds of things that need to be considered when we think about our energy policy as a whole.

We did a study again for the Energy Commission, a few years ago, that looked at the potential in this case to create liquid biofuels from woody biomass, using various modeling techniques. First, the Biosome Model from USDA, then a transportation model. I'm going to skip this. This is just the technology for biomass to liquids.

And we came up with breakdowns of cost curves, NOx emissions potentials from optimally sited biomass facilities throughout the state’s forests. Now, this would apply actually for power facilities as well. These were for liquid fuels, but it would apply for power facilities as well.

And the study was based on thinning and maintenance of forest health. In other words, if you maintained forest health through a prudent thinning program, how much biomass could you generate from each area of the state in those particular areas?

And so, most of them were in the northern part of the state. It turns out that the Sierra is hard to locate because there’s so much national park land, and those were excluded, and there’s so much steep area without access roads. But nonetheless, there’s an opportunity for strategically locating biomass concentrating facilities that will help with the forest fire and forest fire problem, and help maintain forest health.

Now, a little bit about agriculture. I’ll finish here. Agriculture has right now -- it is the source for biofuels. Most of our biofuels in the country, though not all, we use waste, fats, oils and greases as well. Renewable natural gas can be used directly for transportation, but also as a hydrogen and methane source. And according to the Energy Futures Initiative, they see these fuels continuing to play an important role in the future of the state, and also of the country as a whole. And that the development of these renewable gas resources in California has multiple benefits.

So, we have a million dairy cows in the San Joaquin Valley. We did a study for the Air Resources Board, looking at the cost of methane mitigation from manure storage. The cost is less on large dairies and declines as dairy size increases. But those dairy systems are also the most reasonable ones in which to invest recovery facilities.

I'm going to skip this. There's too much information here. These are the various kinds of digester technologies and their cost for mitigation cost reduction. The lowest one is a covered tier one lagoon, with the flare. We don't want to flare it. I'm going to talk to you about an alternative.

These are the four ethanol facilities in California that import corn and produce ethanol that's sold in the market. They also sell dairy feed from those. All of them are evolving into integrated biorefineries. I'm just going to talk about one because we only have time for one at the Aemetis.

Aemetis has a plan to, and in fact is in the building stage of recovering tree woody biomass and converting it into ethanol. There's their gasification system. So, they're going to be able to take some of that woody biomass, perhaps a large amount, and through their lines of technology process create ethanol and blend it with their other ethanol processes. They're going to also make biodiesel from corn oil and other feedstocks.

And they're also installing pipelines from about 20 dairies to bring biogas directly from the dairy to their facility, where it will be conditioned, replaced through natural gas, and be injected into pipelines or used for transportation.

So, you can see they also have plans to do carbon capture and sequestration from CO2 emitted from their ethanol process. So, these traditional corn ethanol facilities are the locus for innovation for advanced transportation fuels and other energy sources in the state.

So, lastly, I'm done. How should we think about in state feedstock production and use for biopower fuels and bioproducts? I think we have to consider that there are important public goods associated with the prudent management of biomass. Those are healthy forests, methane reduction from dairy farming, reduction in the open burning of AG residues. The Delta preservation, which I didn't talk about, but this can be linked and linked to biopower. These are all linked to biopower and fuel production.

This will create a lot of jobs, especially in rural areas, which I call a rural justice benefit. It's not a carbon goal. And that the prudent biomass use for energy has to be part of our sustainable management in the state's economy, and it's the only way we're going to develop a fully circular economy in the state.

So, I want to urge that we not isolate our energy policies and silo them from the achievement of a wider set of important public goods that are and can be integrated with energy solutions that use biomass.

Sorry for going so long.

(Applause)

MR. STEINBUCK: Thank you very much for that. I have a couple questions, but I want to turn to the dais for Commissioner questions and, if there's time, I'll have one or two.

CHAIR HOCHSCHILD: Yeah, just thank you to everyone. You know, this process feels a little bit to me like game planning for a football game with players that we don't yet know we'll have, and maybe some positions as well.

And so, one of the questions that’s on my mind a lot is what the highest order priorities ought to be for R&D to best support our success. I’d like to just quickly kind of go down the line and just hear from each of you.

Don’t feel obligated to, you know, tell your particular technology. Just I’d love your perspective looking at the big picture of where we can make the most headway with our R&D priorities.

And, Leila, let’s start with you as a recipient of Energy Commission grant money. I’d love your perspective.

MS. MADRONE: Yes. So, from an R&D perspective, the place where I see that things are still really sluggish in the solar industry is really on the deployment front. So, we have the right -- this is kind of what I was talking about before. We have the right components, they’re low cost enough. It’s the putting them together in a really efficient way, in an optimized way that takes the best advantage of the land and labor force that I think we really need to focus on. And that could be a different type -- we’re a different type of component that enables those things. But it could also be things like thinking about new ways of automated installation, or new financial innovations.

We've really been a component focused industry and I think we need to start thinking more holistically and system engineering wise.

MR. CASANA: Yeah, I would agree that deployment is a really major challenge, more than developing new pieces for utility scale wind and solar. But there is a point of R&D that I think is really critical in terms of plugging these two very, very viable commercial technologies to actually run the grid and do the work of it, and that's inverter based capacity, where I think there's a huge opportunity in terms of integrating the Western Grid and sourcing power where it's generated to where it can be used in a weather dependent way. It's extremely cheap, extremely affordable.

But you've got to design grid management software that can take inverter based electricity and sort of emulate what physical turbines do when they turn in a large, you know, once-through cooling plant, or a coal plant, or a nuclear plant.

And that research is out there. There's a lot of initial work that's been done. But I think that that's one of the most interesting parts of doing the research that we need to put these pieces together to achieve our goals.

MR. STERN: So, a lot of things that could be researched, but I'll just highlight one. Port infrastructure. There's an opportunity for California to build a very sizeable industry to support the development of offshore wind, not just in California but in other places.

And if this can be thought through in advance, and the investments made in ports, California could have a new dimension to its economy. And there are great examples that are already unfolding in Northern Europe, in Denmark, in Norway. And now, in the East Coast, there are 22.5 gigawatts of offshore wind that are in the planning or contract stages on the East Coast. And many of those, the states are investing in their ports and I think California should make sure it builds on those lessons and develops its own homegrown industry.

MR. LATIMER: For geothermal, the big question is how much can be cost competitive. And the largest driver of cost is definitely your drilling cost and your reservoir performance. So, I think that's where we need to prioritize the R&D dollars. The things that I talked about in terms of flexibility, lithium coproduction are all things that are really nice to have, but the necessary thing is drilling cost to make sense.

And the valley of death for geothermal is very much at the field demonstration level. We have a tendency to fund a lot of small, lab-based projects, and then let technology stagnate for truly decades because they can't get the hurdle of the field-based cost.

The Department of Energy and the federal government is addressing that through the FORGE Initiative to create a field level test bed. There's also a bill in the Senate right now that would do four new public/private demonstration facilities throughout the U.S. And I think California is in a unique position to do something similar in order to create -- identify and create test beds for field deployment of geothermal technology.

DR. KAFFKA: I think that there's a lot of work that can be done or at least focused on carbon capture and sequestration from biomass related facilities and other facilities in the state.

Getting to carbon neutrality will require, I think, things that are basically carbon negative, processes that are carbon negative. And some of the biomass related processes offer that opportunity. And support for both policy and for research in that area I think is really important.

I think it would be helpful to have some additional support and work on advanced gasification systems, especially those that might go at scale. We have a program, the BioRAM Program that supports small scale gasification facilities and that's an appropriate pathway, but there might be room for larger scale ones as well. In fact, I think there are in the right places and times.

But it's difficult to get over the scale from the laboratory scale, or bench top, or small scale to larger scale facilities. And it would be useful for the state to identify processes and good programs in that area.

I also think it's important in the SB100 and other state policy areas to properly evaluate biomass and not to discount it too prematurely, and make sure that our models are in good shape in terms of evaluating it.

It's a difficult process, the lifecycle assessment and co-benefits associated with it. And, in particular, how do we value healthy forests and clean air from wildfire reduction, or from a reduction in open emissions, when that's not strictly a carbon based benefit, but is really, clearly, a large public good.

MR. STEINBUCK: Well, I had one other question that I wanted to ask. We have a few minutes, and so if you'd just give brief responses that would be appreciated.

Tim, you had mentioned kind of the flexibility of geothermal being an option and the example in Kenya. I'm curious what that means in terms of your plant and how you might need to account for that, and how it might affect your cost.

And for others, I'm hoping you can also address just intermittency and balancing the grid and flexibility. So, Dr. Kaffka, kind of the responsiveness of bioenergy resources as being a flexible supply source. And then, for wind and solar, kind of how to manage that intermittency, if there's advances in forecast for example that you're seeing, or any other trends in the space to manage intermittency.

So, if you could address that briefly. I know it's a big topic so, thanks.

MR. LATIMER: For geothermal, I mean the challenge historically has been that there is relatively no marginal cost for operating geothermal. So, under traditional markets, where it's a small enough picture that it doesn't actually, you know, ever exceed the minimum base load requirements that you wouldn't ramp it.

But what I think you're seeing in markets like Kenya, it's so much of the grid that it has to be ramped. And in markets like California, we’ve become such a solar heavy market that it’s shifting the value away from bulk energy to these other services. So, I think the question is, you know, there’s no cost benefit to ramping up and down, but at what point does the value exceed the lost megawatt hours that in California it would be not producing during the day.

And I think that there’s really interesting market design questions around that, and there’s also some interesting technology opportunities in terms of how you can fluctuate the injection and production, what you can do with that excess heat during the day if you choose to monetize it, that need to be answered.

But ultimately, I think it’s a question of market design and we’re at a point where the markets are changing so rapidly in the Western U.S. that the value of flexibility, reliability, capacity is becoming a different part of the picture relative to bulk energy. And so, it’s time to innovate on the flexibility front.

DR. KAFFKA: Well, I probably tried to cover too much. But load following, basically biomass is stored solar energy. That’s what it is. And the existing biomass to energy facilities have some capacity to do ramping. Not so much, traditional boilers are a little harder, but they can follow. But I think the gasification systems have real potential for that purpose. So, that's one of the reasons that I would emphasize that we need to be able to think about it that way.

And in doing so, the co-benefits of the use of that biomass when it's prudently sourced need to be accounted.

MR. CASANA: Sure. You know, one of the things that I often think about is the wholesale grid itself was designed to overcome the intermittency of coal, and nuclear and gas plants. So that when one shuts down for maintenance, there's plenty of power to source the others.

I think that one of the reasons I'm such a big believer in the usefulness of our wholesale grid to solve climate is to integrate, you know, vast amounts of wind and solar from the best parts of the whole grid region. So, that way you get something like a symphony of power. You get extremely high quality wind that ramps up in the afternoon, right as the sun's coming down. That's something that are wires are mostly equipped to solve, but our grid managements software is not quite yet. And you hear about the integrated Western Grid, you know, that's one of the things that I think is most essential in solving that problem.

MS. MADRONE: I'll say that one thing I've seen on the solar front is everyone's talking about how we need storage and everyone's expecting that we're going to build all of this storage. But I haven't seen anyone who's figured out how to make money from doing that. And, unfortunately, that's the way that business is scaled and that's the way we get to large deployment.

There's no value to a company if we help the grid become less intermittent. So, you can be a storage company and no one's going to give you any kind of money for making the grid better.

And so, I think one thing we have to think about is how do we put a value on resiliency? And then, how do we make sure that a company can get paid for creating resiliency on the grid because we don't have that right now.

And that means that building things like storage, now, are just going to be driven by policy and they're not going to be built by real return on investment. And if we want things to grow, they have to be based on real ROI. And I haven't seen any kind of innovation on that front, yet.

MR. STEINBUCK: Great, thank you all. I appreciate the responses and, again, for the very informative presentations and for sharing this information with us. It's very helpful for the SB100 process. So, thank you for taking the time. And I look forward to continuing to engage with all of you. And the last comments are a perfect segue because we'll be discussing storage in our next panel, among other emerging technologies. So, thanks again for all of the comments.

(Applause)

MR. STEINBUCK: So, we're doing a little bit of a transition here to the second panel. As I mentioned before, the second panel is going to focus on a more emerging technology areas that can further contribute to and enable the 100 percent clean energy future. So, we'll be discussing the state of the market of some of these technologies, modeling approaches that may be appropriate, cost trends, and innovations. And again, to inform where we're headed with our analytical effort and, ultimately, pathways for SB100 implementation.

Okay. I've been informed that we're going to take a five-minute break. So, feel free to stretch. We'll reconvene shortly.

(Off the record at 2:34 p.m.)

(On the record at 2:42 p.m.)

MR. STEINBUCK: Okay. And for those that are online, we've just reconvened here for our second panel to discuss a range of emerging technology areas that are going to be supporting our clean energy future.

And so, we'll start off with Miguel Sierra Aznar. He'll be speaking about gas plant retrofits. And he's the CEO and cofounder of Noble Thermodynamics and also a Fellow at Cyclotron Road. And appreciate his partnership through that initiative.

MR. SIERRA AZNAR: So, thank you, everyone. Yes, as Jonah just mentioned, I'm Miguel from Noble Thermodynamics. I'm not here to advocate for natural gas, just in case somebody has tomatoes ready. But my talk, it's around looking at the reality and the fact of where we are and what we have to do to accomplish the goals that we have set forth for California, and the United States and, in general, globally.

So, this is the same old, same old chart that you see everywhere. It's a normally (indiscernible) analysis. You can make a copy based off that, change the number and you have the same picture for California, which is increasing population with -- population with economic growth. Obviously, energy consumption and thus emissions.

Through this, we are all really excited that solar and wind, and more renewables are coming in. I mean, the previous panel talking about geothermal, talking about expanding the market, which I think from my point of view is crucial to actually get this leverage of bringing more solar into California, and more wind into California.

But the truth of the matter is that natural gas continues to grow. We can’t sell in California, but that’s not the case. But at the country level natural gas is actually growing faster than renewables. And that is definitely opposite of celebration, right.

And the reason why is, obviously, natural gas is becoming cheaper and cheaper, and now to a point where it’s completely stable. So, we have a really stable price in the $3 to $4 a million BTU. And that hasn’t gone up. It hasn’t gone down, either. But it hasn’t gone up. And that is motivating a translation and integration of more natural gas as we retire coal, as we retire aging capacity. As we retire, in some cases, nuclear. That is now being substituted with solar all over the country.

And, actually, this image is only showing you to 2018. 2019, actually, natural gas continues to spike in terms of production. Now, is natural gas going anywhere? No, it’s not going anywhere. Natural gas continues to grow globally and there’s also not motive to not celebrate and to be sad about it, but to realize that if we really want to do integral change in our power sector, we really need to face reality. We need to diagnose that this is as it is. And as it is means natural gas continues to grow.

And what that means that the prime movers of the economy, both in California and anywhere, is these three machines, right. And as you can see, I come from a technology background. We are technology developers, so I'm going to talk from a technology perspective.

And these are producing 83 percent of the energy that the economy consumes, right, of these three machines. Now, today, we are looking for these three or these four value propositions. This is what we're looking for. How do we search and how do we find them is a different discussion, but this is what we're looking for. And today, we're only fulfilling the first two. Natural gas only fulfills the first two.

And then, the reason -- and what you can see is this is actually the natural gas growth in the United States until 2019. And you can see in orange is natural gas.

And funny enough, I haven't even plotted natural gas completely. That is just peaking power plants. That doesn't include combined cycles, that doesn't include steam cycles. That is completely gas turbines and internal combustion engines in the country. So, that's about 100 gigawatts of capacity just in peaking plants.

Now, as I said before, this is renewable energy in the United States and this is natural gas in the United States. Right. So, I think we often forget this trend. We get really fixated on how quickly we are growing with solar, the truth is natural gas still there.

And that is not the problem, the problem is the consequences of natural gas is emissions, right, emissions are growing.

Now, let me just bring everything down from the country level to the state level. These are the main numbers for California, right. So, we have, as I said, motives to celebrate in California. But it's still 90,000 gigawatts of power, gigawatt hours of electricity generated in California. It represents almost 50 percent, 46 percent of the energy consumed in California comes from natural gas. And that, as I said, is just fact.

That represents 40 million tons of CO2 a year, and that is the big problem. If want, if we keep to grow natural gas our challenge is not natural gas growth, it's emission growth.

Now, the graph on the right, I want to make emphasis on that because we got to go a step deeper to realize why is natural gas growing. So, we see aging capacities retiring. That is the red line. You see aging capacity disappear in California. But that is being substituted with new combined cycle capacity in green. And most important of all, yellow capacity, which is peaking capacity, which is also growing in California.

Now, let's be true to the facts. And as I said, happy to be in California and we have motives to celebrate. Natural gas will grow next year by 1.5 gigawatts. Renewable energy will grow by 2.7 gigawatts. So, as I said, California is stark different to the rest of the country, but we are still connected to the rest of the country. And you buy technology at a global scale, not a local scale. So, if we want to lead, we have to make sure that we target the source of the issue.

So, the issue is back to the question that the Commissioner asked at the end of the last panel is the value of flexibility. And that is where natural gas comes in.

We have seen, for example, in natural gas, too, that the state's most (indiscernible) -- have improved substantially. We have gone from a heat rate of about 8,000 all the way to 7,000.

And now, I want to make an emphasis on a fact, which is there's 200 miles of natural gas capacity in the state. And that can play a crucial as hydrogen, if the hydrogen economy comes in, that can play a key in actually enabling long-term energy storage. Those 200 miles are already paid for infrastructure.

Now, one of the questions that I was asked, when I was preparing this presentation was, well, tell us about the cost trends and what are the barriers to entry to new, better technology? This is actually one of those challenges in a nutshell is we are going to an electricity market. Right. As we bring more solar and wind, that doesn't impact only natural gas, that impacts everybody. If your price goes negative, everybody hurts.

So, we need to figure out a way in which, first, those prices don't go negative and that we incentivize the right technology to come into the grid. The right-hand side curve is the CAISO 2017, I believe. The LNP average for the CAISO region over an entire year. And we need to, indeed, make natural gas more expensive to incentivize the production of it and the investment in R&D for different, flexible type of capacity.

Now, going back to these two points, right. We need a technology that is indeed the first and the second one, which is cost effective and reliable. But again, we need to align with the goals as set forth by the SB100.

I want to make an emphasis here, specifically in the improved air quality. Many of the policies and I believe (indiscernible) we are very opposed to the offset of greenhouse gases. One of the reasons is when you offset greenhouse gases from combustion, you're offsetting greenhouse gases when you buy solar or procure solar power in Florida. But you're not offsetting the air quality challenges of combustion in the state. So, you can buy many greenhouse gas credits in Florida, but you're still polluting the air in California.

And that's something I think SB100 should look at in motivating companies that use combustion as their main energy conversation to actually improving their activities.

So, in a nutshell, the first five topics are what we see as a challenge from my company's standpoint. And what we see as a solution, and many in this room may see as a solution, is renewable energy plus storage.

I think the first guest, in the first panel mentioned that solar alone won't be able to do it, and storage alone needs to make money. Well, we see this clean flexible capacity in the middle as part of the equation.

Really, briefly, talk about what we do Noble Thermodynamics. So, we are going after natural gas capacity. And from a technology standpoint, we are not going after the type of fuel, we're going after the type of technology. We know that gas turbines and internal combustion engines are really reliable and have been the workhorse of the economy for a very long time. Are we able to turn those machines into tools for the transition for a clean renewable energy future?

So, that's, in a nutshell what we have done. So, we are taking engines of this size and gas turbines, and we can retrofit them in a way that we merge the best of the flexible capacity with the efficiency of the base load to provide a tool that actually the penetration of more solar and more wind by providing them flexibility, at a high efficiency that ensures that it's competitive in the market without the cost increase to ratepayers.

And a key concept, and go back to the 200 miles in California, we are going after hydrogen. If we can change all these machines that are installed in the United States into technologies that enable an energy storage, long-term energy storage framework, now we're talking we have a lot of signed costs already, a lot of infrastructure that can be enable of long-term energy storage and, ultimately, 100 percent renewable future.

So, hydrogen is key. We are going after hydrogen. We believe all these machines can be retrofitted to turn into a hydrogen conversion system, and that's what we're after.

This is a nutshell where we are. We are developing this technology at UC Berkeley. We are not the only ones. There are several other technologies working on concepts. We have others coming out of Texas, others coming out of New York, working on technologies that are very similar. It's looking at making carbon capture in the short term and long term going after hydrogen.

And I mention this for a specific case. We don't want to be lifeline for natural gas. But again, we don't want to deny the truth that natural gas is still there. Now, we are still emitting a lot of greenhouse gases. So, how can we turn all this natural gas capacity today into something that is cleaner? Because we believe that the market will take care of natural case.

As solar, as more solar comes in prices go down, natural gas will remain not cost effective. But today, we need to prevent the locking of more greenhouse gases. Can we retrofit natural gas capacity to capture CO2? When you put that as part of the equation, completely new engineering comes into place. We use carbon capture actually to me all system more efficient. As opposed to be a penalty and inactive thought, we managed to incorporate a carbon capture process into our combustion and conversion efficiency process to actually get high performance.

And that's something that I think many more technologies are doing. And I think funding to develop these technologies is necessary.

Now, thank you very much.

(Applause)

MR. STEINBUCK: Thanks very much, Miguel.

Our next speaker is Jessica Lovering. Despite what her name card says, she's actual a doctoral researcher at Carnegie Mellon, and a Fellow with the Energy for Growth Hub. And she'll be speaking on emerging nuclear.

MS. LOVERING: All right. Thank you for having me. And I was really struck on the past panel, what Tim Latimer was saying about geothermal, how many similarities there are to nuclear. So, I'll touch on some of that. Nuclear's both an old and a new technology, and I'll be focusing more on the new side.

So, I'm sure most of you are familiar somewhat with conventional nuclear power. California is closing our last nuclear power plant around 2025. That's Diablo Canyon Nuclear Power Plant south of here. And right now, Diablo Canyon provides 9 percent of the state's electricity and 18 percent of its low carbon electricity. So, that's a big thing. It's the biggest power plant in the state.

But what I'm going to be focusing on today is new nuclear technologies or we often refer to as advanced nuclear technologies, and the unique benefits that they can provide for deep decarbonization and our energy transition.

Okay. So, what do we mean by emerging nuclear technologies? There's a very big range of technologies that are included under there and I'm not going to go into technological details. But there's many different designs. Maybe you've heard of some things like thorium, molten salt, there's fusion in there.

And there's over 50 companies in the U.S. working to commercialize advanced nuclear reactors. But just in general, to paint some broad strokes, advanced nuclear designs tend to be much smaller than conventional nuclear, by an order of magnitude. They tend to be factory produced or aiming to do factory fabrication.

A lot of them don't use -- actually, most of them don't use water as a coolant. Some of them don't use water at all, in the steam turbine -- or, if they don't use steam turbines.

And then, there's also some that are looking at floating or offshore designs. So, very different technology in a lot of ways from existing nuclear.

And I wanted to highlight two technologies specifically, or two companies that I think are closest to commercialization and might be relevant for the California context. So, those are -- the first one is Oklo, which is actually based in Mountain View. And they 're doing something very different. They are making a very tiny micro reactor, so 1 to 2 megawatts. And they're aiming at off-grid markets and to displace diesel generation.

And this reactor is small, not just in capacity, but also in physical size. So, it fits in one or two shipping containers delivered to site and it's factory produced.

And then, the other one, which maybe you've heard of, is NuScale Power. And that is a bigger reactor, it's 60 megawatts. But they're looking to deploy it not on its own, but in 6-packs or 12-packs. So, when you add those together, you can see the sort of individual models in the 6-pack. That adds up to a power plant that's sort of 350, 720 megawatts. So, that's looking more of a size of a, you know, coal plant or a gas plant. So, that's looking more of competing on grid scale electricity.

Oklo is submitting their design to the Nuclear Regulatory Commission this year. Whereas NuScale is closer to commercialization. They submitted their design in 2016. They're looking to get their license next year. And their first project is going to be providing electricity to a group of municipal utilities in Northern Utah. So, that's very different, again, than traditional investor owned utilities operating nuclear power plants.

So, just some broad strokes, again, on why nuclear matters for deep decarbonization. So, there's obviously zero emissions when operating, both greenhouse gases and traditional criteria air pollutants. And also, very low lifecycle emissions, similar to that of wind or solar panels.

New designs and emerging nuclear technologies have significantly less water consumption and some of them have no water consumption, which could be really interesting in opening up new markets.

Nuclear, existing nuclear can ramp and load follow. It doesn't for economic reasons, typically in the U.S. But current designs can ramp at about 5 percent of capacity per minute. New designs could be even better, particularly high temperature gas-cooled reactors can ramp fairly well.

And some unique features of nuclear that I think have come up a few times and sort of the demand that we might have for them. Nuclear can provide things like frequency regulation, operating reserves, black start capabilities, as well as that load following and ramping capability. So, those are some attributes that can be hard to get in a low carbon system, and so it might be worth considering keeping nuclear on the table for some of those attributes.

So, potential market. As I said, Diablo Canyon's closing. It's 20 percent of our low carbon electricity. Maybe we want to do something to keep it open. But ignoring that for now, it's pretty wide open. there aren't really plans, concrete plans for new nuclear power in California. But I think there is a big market for it, if we're moving towards 100 percent low carbon electricity.

So, I just did a quick back-of-the-envelope calculation, so sort of business as usual projected that in 2045 California will need about 420 terawatt hours of electricity. Now, 60 percent of that has to come from renewables, but the other 40 percent could be from low carbon sources. So, if that was done entirely with nuclear, I'm not saying it should be, but if it was it would be about ten Diablo Canyons. So, that's a lot. That would be about 200 gigawatts. Is that right? No, 20 gigawatts. So, you know, that's a lot of nuclear and particularly if it was done with smaller designs.

But I did put two pictures up here that I wanted to highlight. So, this is a natural gas plant in California. I can't remember which one. And this is an oil refinery. And I think there's a particularly interesting market for nuclear to go at brownfield sites. So, where we have existing power plants that we're looking to close before 2045, because they burn natural gas, they burn coal, they're not economic with CCS, since there's already a lot of infrastructure there, particularly transmission lines, this could be a good place to build a nuclear power plant. And because nuclear has such a small footprint, it could fit into one of these sites.

And the other one is oil and gas -- or, oil refining, nuclear, because it makes a lot of heat can be really good for industrial applications, industrial processes. So, outside of the power sector, there's a lot of uses for advanced nuclear. Industrial processes, as I said, desalinization -- desalination, hydrogen production, things like that. So, it can go beyond the power sector.

And there aren't -- again, there aren't a lot of options for decarbonizing heavy industry, so that's something where nuclear has a unique role to play.

Okay, cost trends. It's pretty difficult to predict what these new nuclear technologies will cost, particularly as we deploy a lot of them. Because, we never really built nuclear in this way. Nuclear has traditionally been stick built, large infrastructure projects. If you want to read more about that, I wrote a paper in 2016 that looked at historical construction costs of nuclear. They're not good, got very expensive.

The goal and the reason that so many companies are focused on factory fabrication is that we would see learning curves over time, like we've seen with wind turbines, and solar panels, and natural gas turbines.

So, what I'm showing here with this graph is some simple projections of projected learning curves for different size nuclear reactors. So, what I'm showing is if you were going to build a 1 gigawatt of nuclear power, depending on what size reactor you build what would the learning curve look like? So, if you built a typical, conventional nuclear reactor, which is 1 gigawatt, you'd only build one of them. And right now, the cost of that, like the AP1000 that is under construction in Georgia, about $5,500 per kilowatt. So, that's expensive. The electricity is still cheap over time, but that's a very big cost burden for a utility to bear.

Now, if you look at building a 60 megawatt reactor, that's like that new scale reactor that I showed, they are predicting what their first of a kind cost will be, they're looking at similar costs for their first one. But because you're building a lot more of them to get to 1 gigawatt, a few hundred, then your costs come down a lot faster. And then, it's much more extreme when you start to look at the 2 megawatt reactor. They are expected to start out more expensive because that's just a very different technology that we haven't built, nuclear so small before. So, even if they start at twice the cost, $11,000 per kilowatt, which is quite expensive, because just to even get to 100 megawatts you're building 50 of those, you see really significant learning.

And the learning rates that I'm learning from these are rates that we see from natural gas turbines or wind turbines. So, you see a lot of learning because you're building so many repeats of that unit.

So, we don't know. It's going to be a lot of risk reduction when we see the first commercial demonstrations are getting built in the next four to five years, and then we'll have a lot more certainty.

But this is something just to keep in mind because California's decarbonization is a longer term effort. It's not going to be done in five years. So, keeping this on the table for the 2030 timeline could definitely be an important option.

And even if costs decline significantly, an additional challenge of nuclear is just how the cost is structured. And this is very similar to geothermal. So, what I'm showing here is the levelized cost of nuclear on the bottom, compared with its main competitor, which is combined cycle gas. And I'm breaking it by the type of costs.

So, you can see that for nuclear almost all of the cost is fixed cost, so capital cost and fixed O&M. Very small share of that is the fuel.

For natural gas, over 50 percent of the cost is variable or marginal cost, both variable O&M and the fuel.

So, what's happening and you're seeing this for existing nuclear in the U.S., is that when the wholesale price of power drops, if it drops even to zero or below zero, nuclear can't shut down and save on money, so they just tend to operate at a loss. So, even their electricity is really cheap in the long run, it can be very hard for them to work in competitive markets. And that's something that needs to be fixed for existing nuclear to stay around and for new nuclear to be competitive in merchant markets.

So, major changes for nuclear, there's a lot. That's why we're not really seeing a lot of focus on it in California. The big one is cost and particularly financing. Now, that could be a lot easier when you're getting to much smaller designs to be private and project financing.

One of the big problems for nuclear is that historically it hasn't been valued as low carbon. It's basically just competing with fossil fuels. California actually has a ban on new nuclear, so that is a big obstacle. But it's not as complicated as an obstacle as, say, market reform. It's just a piece of legislation.

And also, lack of regulatory models for private and industrial owners or operators. So, when you start to think of commercial users or industrial users wanting to buy their own small nuclear reactor, we haven't -- we need to see sort of more innovation in those business models the way we have for renewables.

And just some really broad strokes for policy recommendations. Remove the ban. That's an obviously important one. But also, more technology neutral incentives for low carbon energy. So, clean energy standards, a lot of states are looking at those.

State supported loans or loan guarantees, tax credits. Investment tax credit would be huge for these first couple commercial plants in California.

Also, developing a pilot program for industrial or commercial ownership. There's been a lot of legislation at the federal level in the last few years to support advanced nuclear, looking at deploying micro reactors at Department of Defense installations, or national labs. In California, you could see something similar, maybe with our public universities owning and operating a micro reactor, or some of the national labs we have in the state.

Streamlining approval for nuclear reactors at brownfield sites. And then, I think there could be a lot more work looking at studying how nuclear renewable hybrid systems could be done. So, how nuclear can work with renewables to balance and provide a more reliable and resilient system.

And then, just one closing fact that I wanted to share with you. So, SB100 is aimed at reducing greenhouse gas emissions, but there's a lot of other impacts, environmental impacts from the energy system. And one of them that we don't talk about a lot is land use intensity of energy.

So, what I'm showing here is two different power plants in California, on the same map scale. So, the one on the left is the Ivanpah Concentrating Solar Power Plant, and on the right is Diablo Canyon. And you can see the outline of Ivanpah is these big squares here. And that generates 0.7 terawatt hours annually. Whereas Diablo Canyon, which is this little bit there, generates about 18 terawatt hours annually.

So, if we're looking at a huge build out of renewable energy, this doesn't just take a lot of land, but also a lot more transmission lines, which are also big land issues.

And so, just thinking about the challenges that will bring and what the tradeoffs are in terms of land versus greenhouse gas emissions going forward. Thank you.

(Applause)

MR. STEINBUCK: Thank you, Jessica.

Our next speaker is Alex Morris, who will be speaking on energy storage. And he's the Executive Director of the California Energy Storage Alliance.

MR. MORRIS: Well, hi, everyone. My name's Alex Morris. I'm with the California Energy Storage Alliance. So, thank you for having me and look forward to talking a bit about the state of energy storage and where we're heading and what's going on.

I've heard storage come up quite a bit today, so I'm happy to help, you know, share some perspectives we see from interfacing with our members who are, you know, many of the companies actively developing storage.

I wanted to also say that I think a lot of the discussion today has been really useful and interesting. I think a key challenge is how do we get that last bit of decarbonization, what's the right strategy.

So, part of storage and what we're seeing from the modeling is that we know we're going to need a fair bit of it. And then, I think as we get towards those extreme levels of decarbonization, you know, the problem gets harder and we'll see what roles for storage exists and what types of storage play a role there.

So, a little bit about CESA. CESA was founded in 2009. It's the California Energy Storage Alliance. We're an advocacy group whose mission is to make energy storage a mainstream resources in helping advance a more affordable, clean, efficient and reliable power system in California.

It was founded by some person named Janice Lin, who's actually sitting next to me. Good job.

Here's a snapshot of our 85 members. You know, so this really is a good look of the who's who of energy storage. A lot of these companies are very serious, they're very focused on the California market which is still, really a market just getting started for energy storage, yet is one of the largest markets in the world.

So, for all the fanfare, you'll see that, really, relatively small amounts of progress in terms of installed capacity have been made, yet we still are the earth's leader in the storage market. And we'll talk about that.

Some of the takeaways I wanted to share is that, you know, it's very clear to us that storage solutions are an essential part of this deep renewable integration vision we have, and this transition away from fossil fuel generation. I use the words fossil fuel generation very carefully because, you know, we're not opposed to all types of generation. We think that's great. And I think the challenge, really, is the decarbonization element. So, you could still have spinning turbines and things like that. It’s really just a question of how do you operate those in ways that gets the GHG benefits

And the needs for storage in California are quite significant. I’ll show you a few numbers that are from some of the recent planning studies that will -- you know, for folks in the storage world are quite eye popping.

And then, I think California recognizing the big roles we expect for storage, there’s some obvious recommendations which is we should really keep our momentum. We should explore more diversity in the storage sector. We certainly should look into building longer duration storage. And I think you heard that come up a lot in the modeling discussion earlier.

I think we can look at how storage fits with the resiliency challenge, which is obviously quite compelling, and storage can certainly play an immediate role there.

And then, we want to actualize what we call MUAs, which are multi-use applications. So, ways for storage, particularly behind the meter, to do double duty and help the electric grid.

So, storage is essential for meeting the grid needs. So, you can't even see it, but the CAISO has recently shared how much newly operating storage they have, and it's about 150 megawatts. So, on this chart on the left, it's actually the left column, and it's not even visible. So, there's a teeny amount. Yet, this is -- California represents, you know, basically the biggest storage market in the world.

And just a recent decision on the Integrated Resources Plan directs by 2023 that we add another, you know, over 3,000 megawatts. So, you start to see the increase over 150 megawatts today to 3,000.

And then, by 2025, the Integrated Resources Plan reference plan highlights, you know, north of 42,000 megawatts. So, the growth trajectory for storage over the next 20 years is, you know, very extreme. And this is what causes us to recommend we really want to make sure our toolkit is ready, and we want to be really focusing aggressively on readying ourselves to have the industry positioned and capitalized to move forward and deploy storage.

Another key theme, though, is also the CAISO's illustration of resource needs on the right shows how, you know, the four-hour duration, which has been the standard storage duration in California, has worked sufficiently. But once you have some penetration of those four-hour resources, you may want to shift to a longer duration resource to help absorb the belly of the duck, as they say, and offset the peak.

So, you know, you'll see that come through in our recommendations. And we're very actively looking at how the studies quantify and value long duration storage, and exploring the extent to which we may be underestimating the needs of long duration storage, which we're pretty convinced is happening.

So, many of you know there's a lot of different types of storage. CESA has the benefit of not picking any one. We represent all types of storage, whether it's hydrogen, EVs, or lithium ion batteries. You know, we have compressed air, flow batteries, and all the flywheels, you know, gravitational cranes and trains.

So, you know, our job is to help create markets and provide the right signals and then let the storage companies compete.

And we appreciate the role of the Energy Commission, by the way, in helping incubate the newest technologies through their grant funding programs.

So, one thing I think, though, is the toolkit is certainly going to build, you know, really express itself in the next ten years. It's being built out. Many of you know that lithium has been one of the more successful technologies so far. That's been primarily in this four-hour operating structure. And so, we want to make sure that the toolkit is being built to meet the grid's needs, which we can roughly foresee as reliability, renewable shifting, what I call local or long hold storage. And I think this came up, which is that there's parts of the grid where you do need extended generation capabilities. And there's a whole arsenal of storage technology spooling up to provide that service.

We want flexibility, resiliency, customer services, and then also hybridization. And so, more and more we're seeing storage packaged with solar, wind or gas plants to improve operating characteristics, and improve the value of the resource and, really, leverage a single interconnection. So, a lot of benefits happening with storage.

A question that's come up recently is with this 150 megawatts of storage, you know, what's it doing? How's it operating? And so, here's a quick snapshot from the CAISO's Annual Market Performance Report, from 2018.

So, again, there's very little storage here and, you know, currently there's about 150 megawatts installed, excluding the pump hydro. So, this is really just the newly installed storage. And keep in mind, also, the CAISO's capacity, it's about a 50,000 megawatts. So, this is really just a teeny amount.

And what we've seen is that a lot of the storage that's shown up has, you know, this really elite ramping speed. So, it goes after the fast premium product, which is called regulation. And that's really proving out by how it's being bid and scheduled in the CAISO. So, it's going after this high value product.

But that market's going to saturate soon. So, that market size is actually quite small. So, the regulation market is roughly 400 to 800 megawatts in size. And so, you know, another way of showing that is out of a $10.8 billion a year market, regulation is only $189 million of the revenue.

So, we do expect that as storage penetrations increase, and this should happen pretty quickly, the energy arbitrage roles of storage will start to show up more and more. And we also know that the, you know, companies we deal with every day are acutely aware that energy arbitrage is going to be a very important service for the grid. But it also makes sense that if you have storage already, you're going to go after the high value service, like regulation to date.

So, really, we see in the future, you know, once

-- you know, regulation will always be a premium product. But if there's saturation in that market, the market participants naturally look elsewhere. So, firming renewables, enabling time arbitrage, which is this deep solar shifting which, as we've talked about can be daily, it can be multi-day, it can even be seasonal storage. And, you know, we have companies focused on the seasonal storage, like hydrogen, and these really long hold, inexpensive batteries.

We think you can improve the operational characteristics of existing or new gen by adding storage. And what we're seeing from them is that a lot of these applications are -- they're ready to go today. Some of them need long lead times, so they really want contracts earlier. But generally, I think if you hold a solicitation you can pretty quickly get really competitive pricing that shows the cutting edge frontiers of where storage is at.

And we expect that, you know, while California does have markets to integrate and operate storage, and monetize it, we'll still see those markets evolve. The best example of that is that our whole market pricing system is based around, basically a natural gas, where you have a fuel cost. And as we modify away from that and we go to renewables, where your fuel costs are, you know, much less -- are very different I would say, you have a market that may be shifting more towards renewables and storage. And you have to have that thought exercise of what's the right pricing structure for that. And that will be an issue we wrestle with, certainly.

And here's, obviously, a snapshot of how storage can help with gobbling up the belly of the duck, modifying demand. So, reducing -- absorbing solar during the day or charging at night to ease the ramping needs, and then offsetting the peak in the afternoon.

And then, here's just a -- you know, sometimes people wonder what are the long duration storage solutions? Certainly, batteries can be stacked and racked to do long duration. But you'll also see a whole fleet of companies coming along to compete here. We have hydrogen flow batteries. We have reservoir, you know, pump hydro. And then we have, you know, different sizes of modular reservoirs and cryogenic freezing water, freezing air. So, there's a lot of great opportunities here and all these companies do want to show up and compete in California. I think their membership in CESA is usually indicative that they're trying hard to understand the California market.

So, I think it's a good signal that these companies are showing up and ready to go.

And so, just to wrap up, and thanks again for allowing me to speak, our recommendations are, you know, plan what I've called the essentialness of energy storage. So, plan for it. Continue building our toolkit. Grow and mature our industry sectors. You know, at CESA we look to make sure the whole -- all the sectors are growing, behind the meter, in front of the meter, long duration, short duration. So, we want to make sure that we're growing the segments that will be needed by the grid.

And then, unleash and properly value storage through RPS rules, hybrids, MUAs, resiliency, fast flexibility.

And then, with respect to the long lead time resources, like pump hydro, it seems silly to not allow competition. Like, that's fundamentally not useful for ratepayers. So, one thing we see is that some resources are categorically prohibited from competing in storage solicitations and we think that's counterproductive. So, we'd like to solve that.

And another way to get competition is to do long look ahead solicitations that help these companies at least show up and compete, and give decision makers a chance to know what's the most economic outcome.

So, those are some of the things we're focused on regulatory wise. And I welcome questions as they come. And thanks again for my remarks.

(Applause)

MR. STEINBUCK: Thanks very much, Alex.

Our next speaker is Janice Lin. She's continued her founding ways. So, after founding Storage Alliance, she has most recently founded the Green Hydrogen Council, and she's also the CEO and founder of Strategen.

MS. LIN: Thank you, really appreciate being invited to join you all today, so thank you, Commissioner McAllister and Chair Hochschild.

So, I'm here to talk about green hydrogen. As the former Executive Director of CESA, it's really exciting to be here on a panel with Alex.

I'll start by just explaining how I got interested in green hydrogen. And it started with an analysis that we did in 2016 that asked the simple question of what would the duck chart look like under a 100 percent renewable scenario for the State of California?

So, we took the CAISO OASIS data from 2016, and amped up the renewable production so that 100 percent of the production was renewable, and it exactly equaled demand, and then plotted it over the course of a year. Some of this information was presented earlier, I think by James, from LADWP. But it becomes very obvious when you plot this out that we will have multi-day shortage events, even during the spring and summer, and we will have a surplus in the summer and not enough in the winter and autumn.

So, this begs the solution for a multi-day and seasonal solution. So, this was in 2016 we embarked on a study. Since then, as you've heard, CESA has amended its definition of storage to also include hydrogen storage, among one of quite a few different solutions that are possible.

And in the course of looking at hydrogen, I learned a lot about this amazing flexible resource, and I'll explain a little bit more about the GHG and why I'm now personally working on this.

But first, let me start with the kind of key takeaways for today. And first and foremost, I believe that green hydrogen is part of the solution and essential to meeting SB100 goals. Momentum is happening on green hydrogen all around the world today.

And, secondly, another thing I learned is that hydrogen is already a commodity that's used in so many industries, like to the tune of 70 million metric tons per year globally. And 99.9 percent of it is made from fossil fuels, oil, gas, and coal. And that it is possible to make it from renewable sources, which is what we're calling green hydrogen. And I'll define that in a sec.

And green hydrogen can help us overcome many challenges. One, we can integrate more renewables. It's a great solution for doing something with all that curtailed renewable energy.

Secondly, it's as an amazing vector solution that can go into many, many sectors. It has the potential to decarbonize some really hard to abate sectors. Industrial applications, like steel making, chemicals, shipping, medium and heavy duty trucking as a replacement for diesel fuel, for example. And because you can make this stuff pretty much wherever, it's a way to enhance energy security.

And when I studied hydrogen further and the challenges for green hydrogen, it became clear that there aren't really significant technology barriers because there's lot of ways to make it. Really, the challenges that this amazing vector resource faces is one of market design. How do you achieve scale and cost reduction through scale economies? How do you get compensated for all the benefits provided? It can be an amazing multi-use asset, just like we've been talking about energy storage for years.

And then, finally, how do we make sure we consider green hydrogen as part of our planning toolkit?

Finally, the other thing I'm hoping to share with all of you and get you excited about is that there are multi-sectoral opportunities to address these challenges today. In other words, by zooming out and looking at the potential for applying some of the lessons learned, we frankly learned in hydrogen and other sectors, and finding ways to build large projects at scale, I think we can overcome some of these challenges.

However, progress will require multi-jurisdictional focus, which is a great platform for SB100. I borrowed a couple of slides from the IEA, basically showing that like, hey, this is production today. Globally, I said it's about 70 million metric tons. A lot of GHG emissions. That's the middle column. Because it's made from coal, gas and oil.

And the reason for this is because it's the cheapest way to do it today. However, this green bar shows the cost range of making hydrogen from renewables. And what's interesting is the lower end of that bar is getting awfully close to the ways we make it through fossil energy. I'm going to discuss, and specifically, a couple of examples in a little bit.

So, what do we mean by green hydrogen? Generally, there's the eligible renewable, as we classify renewable resources here in California, through organic conversation, power to gas through electrolysis, and also zero-carbon sources. So, using hydro, curtailed renewable energy, maybe nuclear, a bunch of different ways that have been mentioned today.

The idea is if we can make green hydrogen or zero-carbon hydrogen cost competitive with all those fossil sources, then we have the potential to decarbonize all the sectors that that fossil stuff is, you know, being used for today. So, that's both as an energy resource, as well as a feedstock. And, of course, it's a great multi-day and seasonal storage resource.

So, we're going to talk about a couple of examples. I do want to cover just a couple of slides to give you a flavor, just a little taste for how much progress is happening around the world.

So, here's an example of Australia's view on green hydrogen. They call it their next great export. Australia's been famous for exporting coal. Well, guess what, their future is about exporting renewable energy in the form of hydrogen. They're going to use electrolysis and make it with wind and solar. Then, they're going to either use it as a fuel locally, or convert it into ammonia, or synthetic natural gas, and export it to Japan and Korea.

It should be noted that Korea has a roadmap, New Zealand has a roadmap. Many, many countries around the world already have a hydrogen roadmap. And, in fact, South Korea has targets that 10 percent of their cities by 2030 will be hydrogen based. I think 30 percent by 2040. And last week they announced they're going to convert three cities to all hydrogen for heating, cooling, transportation, and electricity production.

So, in October we decided to launch a new initiative, called the Green Hydrogen Council. We launched it with a meeting in Sacramento, with GO-Biz. And the mission of the GHC is to advance the use of green hydrogen to accelerate the transition to a carbon free energy supply.

Now, we are looking at hydrogen as a means for multi-day and bulk storage in a supportive way to CESA. The focus of the GHC is to look across sectors and find ways to accelerate the deployment of large projects at scale, leveraging opportunities to both scale supply and demand concurrently. So, more of a project orientation.

Consistent with our mission, at this meeting in October we focused on two specific projects, which I'm going to briefly share with you. Now, these are not the end all, be all. They're, rather, examples of what is possible.

Earlier, Miguel talked about using hydrogen in a blend with natural gas as a fuel. And, in fact, there is a large coal plant sited in Delta, Utah, owned by my good friends in Los Angeles, as well as a number of other Southern California Municipal Utilities. This is Intermountain Power Project. It's a 1,200 megawatt coal plant that's getting converted to an 840 megawatt combined cycle.

What's really exciting about this project is that on day one, in 2025, it's anticipated that this plant can burn up to 30 percent of renewable green hydrogen on day one. That will dramatically impact its GHG footprint. That renewable green hydrogen can be made from abundant wind and solar in the area. They've got a number of resources and transmission capacity.

One of the interesting things about this plant is it can take advantage of rapidly falling costs on electrolyzers. This is a cost forecast from Bloomberg New Energy. The green line shows the cost reductions that are happening for electrolyzers from the rest of the world, and the red line is China. I'm told that actual bids for electrolyzer equipment are coming in at the low end of this cost forecast.

And as Alex mentioned earlier that hydrogen is potentially a really great source of really large-scale storage, both for multi-day and seasonal. One of the beauties of the Intermountain Power Project is it sits on top of the world's -- the Western United States' largest salt formation, which happens to be a convenient place to store compressed hydrogen. These are purpose built caverns. One cavern can store about 100,000 megawatt hours. That's equivalent to 200,000 hydrogen buses. And this particular salt field has the potential for 100 caverns. That's in Utah. That's a lot of multi-day and seasonal storage. Each cavern, you can see, is about the size of the Empire State Building.

According to Blumberg, the Energy Finance Salt Caverns are one of the lowest cost ways to store hydrogen. I say one of because, as mentioned earlier, the natural gas pipeline is another really low cost storage facility since it's already built.

And so, what would be the impact on emissions? So, this is just Intermountain Power Project. The legend on the Y-axis is missing an M. It's million tons per year. The red line, going to red dashes is the emissions as a coal plant. And then, starting in 2025, the emissions drop significantly when it gets converted to a gas plant. And the blend, the hydrogen, the emissions drop again to zero, that's the green line at the bottom, if it's the percentage of hydrogen is increased from 30 percent to 100 percent over time.

Of course, this would require building lots and lots of renewable generation in that area. So, that's project one.

Project two, just to give you another flavor for another way that green hydrogen is made, and the gentleman who presented earlier on biomass touched on a lot of this, so I'll go really quickly.

But this is one of those high temperature, thermal conversation pyrolysis projects, called the Carbon Negative Energy Project from Clean Energy Systems. Again, this is just an example. There are other providers that can do this.

This is an interesting project because it was one of the original CEC grant awardees early on. Now, what's interesting about their first projects, in Bakersfield, California, is Bakersfield ranks among the top three most polluted cities in the country for ozone particle pollution and short term particle pollution.

How does this work? That woody biomass, I think it was mentioned earlier that almond farmers have a lot of dead trees. Those trees can be gasified. The gas is then separated into hydrogen to an off taker, and the remaining gas is combusted locally. And the CO2 that comes out of it can be sequestered. That's why it's carbon negative.

The economics work because they have a long term off taker. Coincidentally, it's an oil refinery. Again, an example of a multi-sectoral opportunity. The oil refinery's buying the hydrogen at avoided cost, plus there's a federal tax credit and California's Low Carbon Fuel Standard makes up the difference.

Interestingly, there are a lot of biomass plants that are idle in the Central Valley. If all of them were converted, they could produce about 425 tons of hydrogen per day. Which, just to give you a perspective, that's equivalent to about 15 percent of California's oil refineries' demand for hydrogen. So, it's significant.

And then, finally, I'm wrapping up. I do want to give a shout out for California and its progress on light-duty passenger fuel cell vehicles. We're on track with one of the world's foremost programs. A million fuel cell vehicles by 2030. That will require 700 tons of hydrogen per day.

We are also on track meeting our 33 percent mandate, which is really good for renewables in those fuel cell vehicles. And the impacts are huge. And this assumes only the 33 percent renewable. What if we did all renewable for these passenger vehicles?

And then, finally, I do want to let folks know that there are other off takers that are possible. And these potential off takers for green hydrogen and shipping, trucking, as industrial heat also have a huge GHG impact.

So, finally, I'll just wrap up with the preliminary list of barriers. I feel like we are where we are in green hydrogen as we were in energy storage broadly in 2010. And that is, first, to start by understanding the use cases. What are the supply sources? What are the demand sources? How do we prioritize building up projects and scaling it, and finding cost effective value propositions?

We need to establish an evaluation and procurement framework for evaluating the cost benefits. It would be really cool if it was integrated into the IRP, for example.

We also need to reduce the cost of moving hydrogen from supply sources to demand sources, now. The natural gas pipeline would be a great source.

And then, finally, pricing and accounting structures for production. What about a new tariff? What about the WEC accounting? There's complications. So, again, all of those require a multi-jurisdictional focus, but all are achievable today. And those projects I gave you as an example can happen in the next few years. Thank you.

(Applause)

MR. STEINBUCK: Thanks very much, Janice.

Our final speaker today is Mary Ann Piette, who will be speaking on demand flexibility. She's the Senior Scientist and Director of the Building Technology and Urban Systems Division. Also, a Senior Science Advisor to the Associate Lab Director of the Energy Technologies area, LBNL. Thanks.

MS. PIETTE: Thanks so much. It's a pleasure to be here and I want to thank Commissioner McAllister and Chairman Hochschild for having me here today, and the California Energy Commission staff that organized today's event.

I want to just start by saying California has four decades of great progress on energy efficiency. And I'm speaking on behalf of all the demand side customers in the State of California for our great achievements in energy efficiency. We're moving from a time where our energy efficiency programs have to transition.

We've been doing what I call static energy efficiency, so it's no longer sufficient to just look at how much we use, but when we use our electricity. And that is what we mean by demand flexibility.

I'm going to talk a little about work that we've done, funded by the Public Utilities Commission, and I have a team of people here who have been involved in that research.

So, I'm going to talk a little about the current size of demand response in California, the demand flexibility and DR characteristics, the cost trends, the emerging technology innovation and the future directions.

I have four grid services here in the picture. We call this shape, shift, shed, and shimmy. And shape is responding to dynamic prices. That's our TOU and critical peek pricing. So, load shaping from prices.

Shift, I'll be talking about mostly because that's what we need more of, and we have very little of today. So, how do we encourage people to change their electric load and shift it from that peak time, around dinnertime, to the middle of the day when the electricity is cleaner.

Shed is our traditional DR. And we've been doing that for several decades. I'll talk a little about the status of today's DR. And I'll also talk about what we call shimmy, which is the fast acting DR, which loads can provide that, but we don't need quite as much of it.

So, I want to say in our last study, I'll give you some of the numbers, but the shimmy resource is available from loads, variable frequency drives and other types of things. But again, it's not the focus of the 100 percent renewable future.

So, this is what our current DR programs look like in California. We've got to have about one and a half gigawatts of several categories. The bar on the left is the reliability DR resource. You can see it's by PG&E and Edison, and San Diego is shown there, too. This is mostly the base interruptible programs, and these are sort of emergency reliability programs that are available from customer loads.

Proxy DR takes many forms in the market today. And we have over 200 megawatts of proxy DR. Those are capacity bidding programs that the utilities run.

The DR option, or DRAM, is also a third-party auction that is bid into the CAISO programs. And you can see we have over 200 megawatts of DRAM. And then, price-based DR, which is tariff-based critical peek pricing kind of smart rates.

These are all shed. So, we are still paying people to reduce their electric load on various triggers. And the triggers can be CAISO prices and CAISO conditions, or temperatures that trigger some of the dynamic pricing.

I want to give you just a quick look at some of the things the utilities are doing to try to improve the response to demand response and DR programs. There's a lot of work trying to create incentives to help customers get technology that allows them to participate in automated DR programs.

There work on two-way communications and transactive tariffs. Transactive tariffs are very exciting, where you might pay for a certain amount of your load, and only above that bit you've paid down is exposed to the spot market or the real-time market. So, there is a lot of innovation that has to happen around transactive tariffs.

Rebates and incentives. So, the utilities are trying to understand how to create incentives for automation.

Integrated demand side management. That is the idea where if install a control system for energy efficiency, you also want to acknowledge the controls can provide DR and DF capabilities. So, how can we actually create bundled systems?

In the public utilities programs, the EE and the DR programs are siloed and you can't mix them. So, that's been a big challenge on the regulatory side.

And then, Title 24 requires automated, open demand response technology for many of the commercial building systems. And there's a picture there of something that's called Open ADR that's been in development, funded by the PIER Program at the California Energy Commission. And it's required by most of the utilities for the larger DR activities. And it's used in many of the residential DR programs as well. So, we're working towards trying to create more standard ways to communicate with devices.

I'm going to now introduce you to the study we've been doing for a few years here. And this is the Demand Response Potential Study. We've completed phase one and phase two, which was an initial study on much DR is available in California. And that's where we came up with these four services, the shape, shift, shed and shimmy.

What we found there was shift has the most value in California because that's what we need because of the duck curve.

Shift is worth about a half a billion dollars a year if we could get customer load shapes to be more flexible. I'll go through which customer technologies we've modeled in a moment.

But in phase three we're doing a deeper dive on shift and I'll talk a little about which technologies we're modeling. But, essentially, we want to know how big is the resource, when is it available and how do we get more of it. And shift can absorb most of our over generation today.

Phase four, which we're going to be starting in the next year, is going to create a new dataset. In 2014, we collected 200,000 electric load shapes from throughout the state, with 11 million customer metadata files to create a bottom up characterization of the hourly loads of all customers in the IOU service territories.

So, these are the technologies that we're modeling. And I'm going to you about them by phase. So, the white ones there, in bold, are what we included in what was called phase two.

And now, in phase three we added electrification. So, we did work on residential air conditioning, residential pool pumps, commercial energy management systems and lighting. A lot of industrial loads. And wastewater. Agricultural pumping. And we had behind-the-meter batteries and we had electric vehicles. So, we're using the CEC's EV forecast. And I'll show you about how we're using batteries as a reference for the future.

But we're starting in the future to look at appliances, which are not demand shiftable today because it's hard to get your refrigerator or your washing machine to receive a signal. So, we're working on the technologies to allow customer loads to receive signals and actually automate the time of use response, as well as a DR signal that might happen on a hot summer day.

In phase four you can see we're looking at more distributed batteries, plug loads and even, perhaps, different colored changing of different kinds of lighting technologies.

It is very important to understand while we were talking about mostly supply and grid scale storage, there's a lot of work on the behind-the-meter storage as well. There's work on thermal diodes in walls that can actually change the heat direction of heat in the walls, as with phase change materials.

So, there will continue to be innovation on behind-the-meter customer technology, as well as the grid technologies we've been spending most of the day talking about.

So, this next graph shows you on the right a picture of the CO2 per megawatt hour for -- that's the 2017 CAISO data and it's seasonal. So, essentially what you want to do is you want to move customers' loads to use more of that midday clean electricity and less electricity around early evening. So, if we can create load shifting in customer loads, then we can actually save about .2 tons per megawatt hour and we can help avoid curtailment. We can help arbitrage to reduce emissions. And we can reduce the evening peak and reduce the need for power plants to come online. So, we really want to flatten that that load shape. Some people say call it a halibut, get the duck to fly. There's all kinds of things we can do to the duck. We want to make the duck skinnier by using customer loads to be part of that technology solution.

So, the models that we've developed basically look at 3,000 clusters that represent customer loads by sector, by region, by end use type, and look at the ability of moving load from one time of the day to another.

Every technology we modeled in phase two and phase three exist in today's market. These are not new technologies. But I'll talk a little bit later about the things we need to do to encourage greater uptake of these technologies in customers' premises.

So, we look at the probability of shift. And I'm going to show you what a supply curve for customer end use shift looks like in a moment. And, essentially, we look at a shift usually once a day, but in some cases we might want a morning shift, as well as an afternoon shift. So, in some cases, there might actually be one and a half shifts a day or two shifts a day. In general, there's at least one.

And in 2025, 2020 and beyond there are duck curves every month. And it's very important to note this is a spring problem now, but this shape that we see is a shape that we see in every month in the future.

So, just to give you a little bit of a deep dive on how we modeled the technology, I want to show you what a communicating thermostat looks like in a control system. We looked at the costs for the technology, the operating costs, the co-benefits of energy efficiency and the incentives that the utilities might offer. So, we're basically modeling a variety of costs to value the customer load technologies.

This is a very important graph. This show you, in green, the resource that's available under $500 per kilowatt hour for pool pumps, space heating, space cooling, water heating, HVAC, refrigeration, and process and pumping. And each of these you show in orange, the technologically available resource. And blue is what we show participating today.

So, we have looked at what is available in customer loads and then what do we think is participating based on the incentives in the market today. And we really want to get more penetration of these shiftable technologies.

I'm going to speed up a little. This one shows you the cost per kilowatt hour per year, and you can see that pool pumps are really low cost. And a behind-the-meter customer battery is shown here for reference. And we use that as a reference for when is demand response cheaper than a behind-the-meter customer battery?

We have residential water heating as a fairly expensive load. That's getting a lot of attention, but there's not a lot of it. And I'll show you in a second what that looks like.

This is what the supply curve looks like. This Is a 2030 supply curve. And you'll see the X-axis is gigawatt hours per year. Basically, this is the amount available every day. So, in a sense, you can get about seven -- and the price reference of a battery is about

$150 of levelized costs. So, this is assuming a 10-year life of these technologies, how much does it cost to install them.

I will speed up. And I have a look here at the way we modeled electrification. So, we modeled the adoption of electric space heaters and electric water heaters in the residential sector. That was in what we called phase three that we're about to make public. It was not in phase two and it will be in phase four. We will do commercial space heating and water heating as well.

This is what the hourly loads look like when you -- in 2025 and 2030 you can see the electrification come in, in the loads. I'm almost done. I want to just give a shout out to the Load Shift Working Group that's been working on what kind of pilots we need for the state, because we are not paying for shift today. So, the Load Shift Working Group was coming with what kind of pilots are needed to create incentives for customer load shifting.

And this is my last slide. I want to emphasize that we have a lot of technologies that are coming on the market today. Some of these are thermal storage, some of these are electrification. I want to mention that we need something called the statewide pricing pilot 2.0. About 15 years ago we had a statewide pricing pilot. We worked with time of use and critical peak pricing for residential, and we had a manual, and automated technology response. And we need that sort of thing to get customers familiar with responding to digital tariffs. We need machine-readable electricity prices that we can send to devices. So, the prices to devices theme is a critical one for us to create demand side incentives for customers to address the duck curve.

And here, on my deep duck, on Memorial Day this year, 16 percent of the electricity we generated from renewable sources was not used. It was the largest day ever that we were unable to use the load that we generated.

And I will thank you for your time. And appreciate the sponsorship from the PUC and the CEC.

(Applause)

MR. STEINBUCK: Thanks so much, Mary Ann.

So, I want to give Commissioners an opportunity to ask any questions or provide any final comments before we turn to the public comment period, as we're running a little bit behind.

CHAIR HOCHSCHILD: Just briefly, this is terrific. Thank you all. Just a brief question for the gas, for you. Just looking ahead of me, when I think about adding new gas capacity in California, I mean you have to look at three things, right. What's the price of gas going to be in the future? What's the price of water going to be in the future? What's the price of carbon going to be in the future?

Just your perspective on, you know, looking ahead at the carbon risk, the price risk associated with that.

MR. SIERRA AZNAR: Thank you for the question. Yeah, I think from my perspective, as I said, we look at this gas technology as a technology, not as a fuel source. I think carbon pricing and the cost of carbon is an externality that should be included in the market.

I think something that nobody talked today, except on the first panel, about transmission, right, is as we bring more renewable in, and we can do more demand response, we are killing the incentive for economic revenue. Like if you are a company and now our marginal price is going down, your (indiscernible) is going down, but you're not making any money. So, I think if we want to maintain, as I said, incentivize hydrogen storage, incentivize solar and wind, we need to price carbon. I think, actually, that is something that from a technology stand point is beneficial to us. Because that means that incentivize emitting technologies to speed up and invest in R&D, just to make sure that they convert. As I said, we are converting machines to something that is clean. It's not about capturing CO2 or not. We are really happy with carbon capture technology. I think we want more R&D funding, if possible, to develop more. But it has to be spent in figuring that the carbon cycle is closed. Because if you're going to just hand a credit line to the fossil industry, that is not really solving an issue. You're just handing kind of like a postpone and keep burning more fossil fuel.

But carefully designed legislation can actually help develop carbon capture that closes the carbon cycle.

COMMISSIONER MCALLISTER: So, I have a couple questions. I'm going to start sort of in reverse order for Mary Ann. Thanks again. I really am -- it's great to see this long trajectory of work that just leads to, you know, in a very I think intentional way. And so, just congrats on all the good work. And, hopefully, we can find ways to keep supporting it.

So, a couple questions on -- well, one point and then a question. I would just point out that actually, in our Business meeting this week, we opened an OAR on load management standards and plan to work with the PUC on this. And what we're doing is just, I think, extremely complementary and lends itself to working together.

And so, all the things you said, like machine readable, you know, all these different technologies and how we can make that happen. Absolutely, you know, invite and I know you'll participate in that. So, that will be great.

Let's see, I guess my question is -- well, I'll just also include, you know, we have SB 49, which is going to focus on demand flexibility of our appliances. And then, we also have Title 24 for 2022 and we're going to focus on commercial and multi-family, and figure out how we can incorporate some of these demand flexibility capabilities as, you know, mandatory or voluntary elements of new construction.

So, I think all those things really are leading in a place where we can have a coherent discussion, and I'm really, really optimistic about that.

It seems like sort of the situations, you know, like things are converging. We're getting sort of a nice convergence on that.

So, my question is do you -- so, open ADR, you know, I think is great and, you know, happy that it exists. I guess, what's your feeling currently about, you know, what that -- is there like a killer app that's going to allow plug and play for these resources, so that all of these literally billions of points of interconnection, potentially, can at low cost, with low friction communicate and work together? Is it building open ADR? Is it something different?

MS. PIETTE: Yeah. So, open ADR was really designed for events. And an hourly price can be an event. But a tariff may have characteristics that if you read it for one month it has when the high price is, how much is the price on the weekend.

So, this digital tariff or machine readable tariff is something a little bit different than open ADR. Open ADR has pieces of it, but I do think -- and I've been talking with the utilities about how to get, how to automate time-of-use response. And it can be a one-time download that that thermostat knows the schedule of the time-of-use prices. it doesn't have to be continuously communicating, but we need a representation of a tariff that maybe we update it once a month, and you check your i-Phone, just like your updates. You know, which we all hate when you have to update your software. But some sort of way that you can represent the tariff.

Now, EV tariffs, resident TOU -- PG&E's going to be on residential TOU next October. And we want to be ready so that people can have their home on -- Ask Alexa, should I run my dishwasher now technology, that is it in the cloud or is it in a local gateway. We need some pieces that aren't there, yet.

COMMISSIONER MCALLISTER: Does it have to be a tariff. I mean, can it be just, okay, yeah, like a carbon content signal or something like that, that's not --

MS. PIETTE: It could be a carbon content signal, but they better save money on their bill.

COMMISSIONER MCALLISTER: Yeah. Yeah. So, I think, I guess --

MS. PIETTE: So, that's what the problem is, the carbon tariff and the retail aren't that coupled.

COMMISSIONER MCALLISTER: Yeah.

MS. PIETTE: It's because that's part of the problem.

COMMISSIONER MCALLISTER: Yeah, well, they need to be. It would be great if we could bring those together.

MS. PIETTE: They need to be. That's it, if they were, then I would say yes.

COMMISSIONER MCALLISTER: Yeah, okay. So, I guess I'd just encourage people to think about whether the state has to get in the middle of that or whether there's some kind of, you know, what's the -- how the stakeholders get mobilized to come up with that solution.

MS. PIETTE: Yeah.

COMMISSIONER MCALLISTER: Because I think there's a real bias towards -- at least I'm perceiving that there's a real bias towards proprietary approaches and I think that's not going to get us -- you know, my gut is that that's not going to get us --

MS. PIETTE: Yeah, I think the more we standardize it further down.

COMMISSIONER MCALLISTER: Okay. Well, great. Thanks a lot. That platform question I think is really key.

So, for storage, maybe to either or both of you, Alex and um -- Janice. Sorry Janice. Can you give us a little bit more thoughts about the path to market for the seasonal storage? Like what's the value proposition going to be to like connect point A to point B, like where we are to where we need to go?

MR. MORRIS: Good question. So, seasonal storage, what's the path to market. I think right now there isn't one and we see no clear reliability signal at all for having capability that lasts that long.

I think this is not just something that storage sees. I think a lot of natural gas resources would also highlight this. And that's been okay so far, but now we're entering, you know, a new world where we're letting -- you know, sort of winding down the old fleet, moving into the new fleet, and so we do need rules and price signals that will address that. Our reliability products have basically been designed for peak day needs. And we just fundamentally know that's not what's needed.

So, I think some regulatory reform is one of the first areas of action. And, certainly, there's a lot of smart groups and agencies in the state are looking at that. But it hasn't yet translated to a product that's fungible, and transactable, and bankable, yet. It's really been energy oriented or sort of short duration capacity oriented and that's not doing the job.

COMMISSIONER MCALLISTER: Yeah.

MS. LIN: And I'd like to add to that that there's sort of two levels. There's system level, but also these, you know, frequently now occurring PSPS events --

COMMISSIONER MCALLISTER: Yeah.

MS. LIN: -- which can be several days. There's one happening coming up, apparently. So, I think there's an opportunity to think about that in terms of resiliency for micro grid compensation mechanism.

COMMISSIONER MCALLISTER: Yeah.

MS. LIN: And then the other thing I was going to say, which is where I thought you were headed is like the technology solution set. Is that your question?

COMMISSIONER MCALLISTER: Well, I mean to invest, to bring investors in you've got to have some path to a business model that works. And so, I guess that's a technology-specific, potentially, question but --

MS. LIN: Definitely. But the thing I wanted to say is that there are solutions that exist today, where there really isn't a big technology hurdle. And it really is one of finding the compensation pathway.

COMMISSIONER MCALLISTER: Yeah. Okay thanks, appreciate that.

And, actually --- well, go ahead.

MR. MORRIS: I just wanted to add on that, you know, when we -- when we, the state, started on this storage journey, a lot of it started with AB 2514, which, you know, basically said is our -- you know, let's look at how to transform this energy storage concept into reality. And I think a question is still lingering from there and worth revisiting is how do we sufficiently develop the toolkit? And I think your point is, well, maybe we've developed a lot of the toolkit, it's been great. It's a good success. But maybe it's not sufficiently developed and we need to do more work and road mapping on the pathway for those longer duration resources.

COMMISSIONER MCALLISTER: Anyway, thanks a lot. Actually, I don't think anybody mentioned that today, in the Legislature, there's been a hearing all day about the PSPS. And Secretary Batjer -- President Batjer has been there and a bunch of others. So, you know, clearly this is a lot of important discussion going on.

The last question is on nuclear, Jessica. So, where, could you give us a little, maybe just a brief, very brief, because I know we're over time, but kind of -- well, really, two questions. One, are there -- where would you predict in the WEC, or in the Western U.S. we're likely to see nuclear development, I mean given there's a moratorium in California. But where might there be nuclear power going on to the Western Grid.

MS. LOVERING: Yeah, I mentioned the NuScale's first project, which is going to be selling electricity in Utah, but actually built in Idaho. And UAMP's the utility that is buying that electricity. They are shutting down a very old coal plant and they wanted something of a similar size to replace it.

So, I think with the way markets are structured right now, it's likely you will see the next few projects like that be likely municipal utilities looking to shutter base load plants that are fossil fuel powered, because it's a better sort of one-for-one replacement.

COMMISSIONER MCALLISTER: Okay.

MS. LOVERING: And it can be cost competitive with coal. So, I think that's pretty likely.

COMMISSIONER MCALLISTER: You didn't mention, that I heard, the waste issue. And I guess, what's the sort of current on, you know, whether -- well, what's the current thinking on that? You know, DOE is 30 years, you know, breaking the law. So, what are we expecting moving forward.

MS. LOVERING: Yeah. So, it's a problem that needs to be solved no matter what we do, even if we phase out nuclear and stop generating, we still need to come up with a solution. So, my focus has been on, you know, there's been some movement in Congress lately about restarting the process of whether to have one centralized facility, or several regional waste storage facilities, and that just needs to go forward no matter what.

I think one interesting thing with these micro reactors is you would not be storing spent fuel on site when you have a lot more of these very small reactors, the even smaller. But most of them are looking at is you would fuel a reactor at the factor where you build them, and ship them to the site sort of sealed, fully fueled. They run for maybe 10 to 30 years and then you send them back to the factory and --

COMMISSIONER MCALLISTER: Recycle them.

MS. LOVERING: Yeah. So, the fuel is handled in a centralized facility. So, right now, we're storing spent fuel at sort of 70 locations around the country, at all the power plants. And there's reasons maybe that's not the best idea.

So, the factory fabrication can kind of help with that in sort of keeping fuel handling and also spent fuel in fewer locations.

COMMISSIONER MCALLISTER: Great. Thanks a lot. Thanks, everybody, for a good panel.

MR. STEINBUCK: Yeah, I just want to add my thanks as well. I really appreciate the rich set of information that you've brought forward to inform this discussion. You're welcome to continue to sit there for a few minutes, as we have some public comments from our Public Adviser.

MS. GALLARDO: Okay, now I can hear myself. My name is Noemi Gallardo. I'm the Public Adviser for the Energy Commission. And we will kick off public comment in the room, first, and then we'll go to WebEx in case anything comes through.

You have up to three minutes to speak. You'll have a flashing sign over here that your time's up, in red.

So, I was asked by two members of the public to read their comments. The first one is from Michael O'Boyle. First, how should we think about how transmission costs for out-of-state wind and other resources will be paid for? Other states will benefit from increased transmission capacity, particularly AC lines. Will they pay? Can multi-state agencies work together more effectively to optimize?

The second comment is from Bruce Ray. What about fusion power? For decades, fusion power has been 25 years in the future. Is that still true?

All right, so the next comment, someone who filled out the comment card gets priority. Elise Hunter from Grid Alternatives.

And then, other folks in the room, please feel free to line up behind either of the two microphones.

MS. HUNTER: Hello. Can you hear me?

MR. STEINBUCK: Yes.

MS. HUNTER: Great. Hi, my name is Elise Hunter. I'm from Grid Alternatives. We are a nonprofit organization based in Oakland, but we have presence all over California. Our mission is to provide under-served communities with access to clean technologies. And we're a program administrator of low income solar programs, including the SOMA Program and the SASH Program in California.

I wanted to make a comment about equity. It was brought up at the beginning of the workshop. And make the recommendation that the SB100 report include at least a chapter on equity, if not a whole separate report on equity.

We had a lot of really interesting discussions today on the mix of resources, the cost of resources, the potential benefits of resources, but not necessarily where those resources are going to go, and who is going to get them, and when.

And I think those are really key questions that we need to answer in SB100. As you know, the piece of legislation does call out disadvantaged communities and the need for decks to access these resources.

We've got a great foundation report, I believe, in the CEC's SB350 report, which talks about barriers for these communities in reaping and having access to solar technologies. So, now that we understand the barriers, how do we ensure access? And this report could look at best practices, programs that are out there that have succeeded or maybe not succeeded, and make some really clear recommendations on how we're going to make sure that low income communities and disadvantaged communities can have these technologies.

So, I just wanted to put that out there. Grid Alternatives, as one stakeholder, is really interested in participating in that effort. And I look forward to discussing this more in future workshops and meetings. Thank you.

MS. GALLARDO: All right, anyone else in the room have a comment?

Okay, anyone come through on WebEx?

Okay, I think we can close public comment. Thank you.

MS. GUTERREZ: Okay, at this time I will look to Commissioner McAllister to see if there are any further closing remarks?

COMMISSIONER MCALLISTER: No, nothing substantive. I just want to thank staff for putting together a great workshop. Again, I really like to see the collaboration with our sister agencies. And I know there's just a lot of work behind the scenes. Tara, I know you've been sitting there quietly all day, but moving and shaking behind the scenes there, too.

And absolutely want to thank all the panelists. I mean, you really are the tip of a spear of a lot of people behind you that are doing great work. And, you know, we do need solutions, but we've got a lot of good stuff going on.

I mean, the technological landscape is incredible, right. And I think a number of people have brought up that many of our issues are with just the complexity of the institutional landscape. You know, and that in large part the regulatory landscape, but not entirely.

And so, you know, I think collaboration, and communication, and platforms for discussion are really where the details get hashed out on this. And so, you know, we're committed, as I know, well, all the agencies are to work together and, you know, collaborate as much as we need to on some of these bulk issues with the ISO, and others, to make sure that all the different pieces of the puzzle are fitting together as best they can, and in a timely way. I mean, I think we all acknowledge how much urgency there is. We're in the middle of living climate change and it's just every day more clear.

So, yeah, just everybody keep your sleeves rolled up and we'll have another opportunity to talk soon. And, you know, also outside of this room and beyond, you know, keep us all accountable. You know, like pay attention. And if we're too slow, tell us, because we need that little -- we need somebody breathing down our neck to get it done. So, you know, speaking for, you know, myself. I won't speak for all the Commissioners. But, you know, I think it's good to have a little urgency injected into the proceedings.

So, again, thanks a lot and we'll see all of you at the next opportunity, and Aleecia will give you some of those details

MS. GUTERREZ: Great. And speaking of platforms for discussion, we will -- we are going to hide away for a couple of months to do some modeling, and then we will resume our workshops that will dig into some of the details looking at the modeling results, including reliability, equity, land use, and some of the other topics that are called out in legislation.

So, we will continue to update our webpage, which is shown here. If you have written comments, especially those that are more technical in nature, please submit those to the CEC docket listed here. We are asking for comments by December 2nd.

And I think with that, we will give a big round of applause for all of our panelists and presenters today. Thank you very much.

(Applause)

MS. GUTERREZ: And that concludes our workshop for the day. Thank you very much for hanging in there with us.

(Thereupon, the Workshop was adjourned at 4:10 P.M.)