| DOCKETED | |
|---|---|
| **Docket Number:** | 23-IEPR-03 |
| **Project Title:** | Electricity and Gas Demand Forecast |
| **TN #:** | 254927 |
| **Document Title:** | Transcript - IEPR COMMISSIONER IEPR COMMISSIONER WORKSHOP ON THE CALIFORNIA ENERGY DEMAND FORECAST RESULTS PART II |
| **Description:** | 12.19.2023 - Transcript - IEPR COMMISSIONER WORKSHOP ON THE CALIFORNIA ENERGY DEMAND FORECAST RESULTS PART II 12.19.2023 |
| **Filer:** | Raquel Kravitz |
| **Organization:** | California Energy Commission |
| **Submitter Role:** | Commission Staff |
| **Submission Date:** | 3/8/2024 10:24:08 AM |
| **Docketed Date:** | 3/8/2024 |

STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of:

| | |
|---|---|
| Commissioner Workshop - California Energy Demand Forecast Results Part II | Docket No. 23-IEPR-03 |

CEC IEPR COMMISSIONER WORKSHOP

ON THE CALIFORNIA ENERGY DEMAND FORECAST

RESULTS PART II

REMOTE ACCESS VIA ZOOM

TUESDAY, DECEMBER 19, 2023

12:30 P.M.

Reported by:
Elise Hicks

## APPEARANCES

COMMISSIONERS

Siva Gunda, Vice Chair, CEC

Patricia Monahan, Commissioner, CEC

Darcie Houck, Commissioner, CPUC

Genevieve Shiroma, Commissioner, CPUC

STAFF

Heather Raitt, Director, IEPR Office, CEC

Heidi Javanbakht, Manager, Demand Analysis Branch, CEC

Nick Fugate, CEC

Ingrid Neumann, CEC

Quentin Gee, Manager, Advanced Electrification Analysis Branch, CEC

PRESENTERS

Mariko Geronimo Aydin, Lumen Energy Strategy

Onur Aydin, Lumen Energy Strategy

INDEX

P R O C E D I N G S

12:31 p.m.

TUESDAY, DECEMBER 19, 2023

MS. RAITT: Good afternoon, everybody. Welcome to today's workshop on the California Energy Demand Forecast Results Part II. So this one is to talk about the hourly and peak results, and I'm Heather Raitt, the director for the Integrated Energy Policy Report, or the IEPR for short, and this workshop is part of the CEC's proceeding on the 2023 IEPR.

So this is a remote-only workshop using Zoom. We are going to be recording and we'll post an audio recording shortly after the workshop, and then a written transcript in about a month or so following the workshop.

To follow along all the materials are docketed and posted on the event page for this workshop. If you go to the IEPR webpage you can find it.

After the presenters we will have some opportunities for attendees to ask questions of the presenters. You can use the Q&A feature if you're on the Zoom platform to submit questions for presenters. And then alternatively, at the end of the day, we do have an opportunity for public comment, and we'll be limiting those to three minutes per person with requests for one person per organization. And then finally we always welcome written comments, and those are due on December 29th.

And with that I'll just turn it over to Commissioner Monahan to open the workshop for us.

Thank you.

COMMISSIONER MONAHAN: Thanks Heather, and thanks to the team.

And I'm just going to be very brief because this is really Vice Chair Gunda's baby I'd like to say. And I'm happy to see Commissioners Houck and Shiroma on the virtual dais, so I'm looking forward to your comments and input today.

I think as we all know the demand forecast is central to energy planning and policy in the State of California, and it's really critical for utilities to be able to procure the resources that we need and for the PUC to guide that process. So I know this has been a challenging year to be able to continue to update the forecast with the best available information to make sure that we're attentive to climate impacts and we're incorporating those into the modeling.

And so I just really look forward to the discussion, and I'm just going to pass it right over to Vice Chair Gunda for his input.

VICE CHAIR GUNDA: Thank you, Commissioner Monahan.

Welcome, everybody. Thanks for joining us on the 19th, the afternoon, just as we're all going into the holidays. I really appreciate all of the public joining us, and to Commissioner Shiroma and Commissioner Houck as well from CPUC.

As Commissioner Monahan mentioned, the forecast has such a pivotal role in the energy planning, especially given the climate policy we're all working on in terms of electrification and the clean grid, which is largely intermittent today. So we really need to understand the hourly impacts well and be able to quantify them to secure the necessary grid to keep the lights on and get us through this reliable journey.

Especially coming out of 2020 and the past couple of years, the climate impacts and the ability to improve the forecast based on the future climate impacts was a key consideration. Historically the forecast always relied largely on historical data. And, you know, something that we have taken to heart since 2020 is really thinking through how do we enhance a forecast based on future impact, electrification, deployment of behind the meter resources, the DERs, but also climate, and how do we really get that right?

So really excited to listen to Lumen's presentation today and staff presentation on the results.

So looking forward to the discussion, and before we jump on to the staff, I want to pass it on to Commissioner Houck for her comments.

COMMISSIONER HOUCK: Thank you, Vice Chair Gunda.

Good afternoon, everyone. I want to thank the Energy Commission staff for hosting and moderating today's second IEPR workshop on demand forecast results. I had the opportunity to attend the first workshop on December 6th, where CEC staff presented the results of the annual electric and gas demand forecast. I really look forward to hearing the presentations regarding the hourly peak electricity demand forecast today.

I want to also extend thanks to Vice Chair Gunda and Commissioner Monahan, and again all of the CEC leadership on the 2023 IEPR, as well as President Reynolds and my fellow PUC commissioners for their coordination with the Energy Commission on this work.

The IEPR is foundation for statewide energy system forecasting and planning in California for the broader electric system planning inputs from the Energy Commission's demand forecast, which are incorporated into the PUC's Integrated Resource Plan, or IRP, for all load-serving entities, which then feed into the ISO's transmission planning process. California's electricity system is undergoing a significant transformation on the pathway to reaching our SB 100 goals, as Vice Chair Gunda noted, with a high penetration of renewables, electrification of buildings and transportation, and deployment of behind-the-meter distributed energy resources. Demand-side resources continue to play a critical role in ensuring that we have load flexibility and can meet our SB 100 goals. So with the anticipation of a high level of DER, penetration, particularly in the transportation sector, we're seeking to optimize the integration of DERs within the distribution grid while making sure that the rates customers pay are affordable.

And I just want to underscore the importance of the IEPR forecast, which is a critical component that we at the PUC are heavily relying on when asking investors and utilities to assess their investments in distribution infrastructure, and again, the IEPR continues to be an integral piece of the statewide planning process.

And with that, I again just really want to thank the CEC, Vice Chair Gunda, and Commissioner Monahan for all of your coordination with us and your dedication to this important topic and hosting today's workshop. And so with that, I again really look forward to hearing the presentation of the work today.

VICE CHAIR GUNDA: Thank you so much, Commissioner Houck.

Really important points that you discussed about DERs and understanding the impacts of that. So thank you for your coordination as well with CPUC.

Commissioner Shiroma?

COMMISSIONER SHIROMA: Yes.

Thank you, Vice Chair Gunda and Commissioner Monahan.

Good afternoon everyone. My pronouns are she/her.

I very much appreciate sharing the dais with you. I also echo my appreciation, respect, and thanks for the tremendous work that the Energy Commission is doing, the essential work through this IEPR effort.

The energy demand forecast, the framework, the protocol, the approach is critical for our sustainability as the Golden State. The grid has many changes going on that we can anticipate ahead, investments being made. And meanwhile, we do have climate change that is overlaying this effort. The forecast results are critical, essential for all of us as sister agencies as we chart the path for our -- again, for our Golden State.

Again, I want to thank the staff of the Energy Commission. Its very careful analytical work, expertise, sophistication, understanding, almost, you know, it's almost a DNA thing, us being able to navigate the very extensive tools at play, bringing in folks like Lumen towards ensuring that we are on a solid path.

So thank you. Appreciate being here today. I look forward to the presentations and discussion.

Back to you, Vice Chair Gunda.

Thank you.

VICE CHAIR GUNDA: Thank you, Commissioner Shiroma.

It's so lovely to have both you and Commissioner Houck joining us from PUC, and it's been such a wonderful collaborative process thanks to Commissioner Monahan's leadership on the vision of this California report. So thank you, Commissioner Monahan.

And as I call on the staff, I wanted to share my final thanks to the IEPR team and the energy assessments, the technical team, for their continued work on making sure the IEPR is accessible, but also the results we present today are rigorous and have a strong stakeholder access and feedback.

So with that, Heather, I'll pass it back to you.

MS. RAITT: Great, thank you. Great, thanks.

So actually, I'll just pass it on to Heidi Javanbakht to open it up. She's the Demand Analysis Branch Manager. So go ahead, Heidi.

MS. JAVANBAKHT: Alright.

Thanks, everyone. Good afternoon and thank you to everyone for attending today.

I realize this is a particularly busy time of year with the holidays coming up, so I really appreciate those that were able to make the time today.

I'm going to kick us off with an overview of the forecast and the updates that we made for this year.

Next slide, please. And next slide.

Okay. So a lot of this was already touched on by the commissioners, but the CEC's California Energy Demand Forecast, which is often referred to as the CED or the IEPR forecast, is foundational to procurement and system planning in the state. It's used by the CPUC for integrated resource planning and by the California ISO for transmission system planning. It's also used by the CPUC and utilities for resource adequacy requirements and by the utilities for planning.

The forecast is a 15-year forecast of electricity and gas demand in the state. We project annual electricity and gas demand and hourly electricity loads. The forecast includes scenarios reflecting various levels of adoption of energy efficiency, building electrification, and transportation electrification. The forecast also includes one-in-X-year net electricity peak estimates. And we update the forecast annually with a comprehensive update in the odd years.

Next slide.

This year, 2023, is an odd year, and we made substantial updates to the forecast.

Each year we update inputs with more recent data, but this year the team also transitioned to using new models for the residential sector and for modeling adoption of behind-the-meter PV and storage. The team also improved the methodology for determining the historical capacity of PV and storage.

For the additional achievable energy efficiency and fuel substitution components, the team refreshed the Title 24 and program accounting.

The team also collaborated with CARB, the Air Resources Board, on the assumptions used to model CARB's proposed zero-emission appliance standard, and they kicked off the rulemaking process for that standard last spring. For the 2023 IEPR forecast, this proposed standard is included in both the planning forecast and the local reliability scenario for electricity system planning, whereas in 2022, the standard was only included in the local reliability scenario and was not included in the planning scenario.

Lastly the team shifted to using newly available climate data in place of using historical weather data. And the next presentation from Lumen will go over the progress made in this area, as well as some of the challenges they've encountered.

And I really want to express my appreciation and gratitude to the team for the significant effort invested in this component throughout the past year. It's a big team that includes our forecasting team; our colleagues in the Energy Research and Development Division at CEC; Lumen, who you'll hear from next; Eagle Rock Analytics; and numerous others involved in the Cal-Adapt Analytics Engine. This is a vitally important area for improvement for energy system planning, and there's limited prior research to draw from, so we're fortunate to have a really smart and dedicated group working on it.

However, because it is a new endeavor, some unforeseen hurdles arose during the initial implementation, which led to delays with the hourly electricity forecast this year.

So I also want to emphasize that the results presented today are a draft and are still being reviewed by our team.

Next slide.

And the next couple of slides are just to set the stage for the hourly results. I wanted to do just a very high-level recap of what was presented on December 6th.

So first is the households and population projections from the Department of Finance that feeds into our forecast. And as you can see from these charts, both the household projections and population projections are growing at a much slower rate than was projected in 2022.

Next slide.

And then these are the rates. We are seeing significant electricity rate increases in the near future, primarily due to the need for wildfire mitigation measures, and so this means that the electricity rates used in the 2023 IEPR forecast are higher than what was used for the 2022 IEPR forecast. So the red line in this chart is the 2023 forecast and that blue line is the 2022 forecast.

Next slide.

So those factors were the main drivers behind a lower forecast of annual electricity sales in the short term, which is shown by the two blue lines in this chart, compared to the 2022 forecasts shown in the orange and yellow lines. However, there are other factors behind this as well, and if you missed the December 6th workshop, I encourage you to go back and watch that recording.

The other big change from last year, which I mentioned earlier, is that CARB's proposed zero-emission appliance standard is incorporated into both the planning and local reliability scenarios this year. This standard, as proposed, would go into effect in 2030, and so you can see an inflection point there where the 2023 scenarios start to ramp at a higher rate.

Next slide.

And I'll leave you with this slide of the IEPR workshops on the forecast for this year. Today is the final workshop where we'll cover the draft peak electricity demand results. We will continue to review these results, and may make some adjustments. At the same time we will review any comments submitted after these workshops, and we are aiming to post final results in January.

I want to thank the CPUC, the Air Resources Board, the California ISO, the IOUs, and many others who provided valuable input and feedback on our forecast this year.

And with that, I will hand it off to Mariko from Lumen Energy Strategies to go over key findings in climate data analysis for demand forecast integration.

MS. AYDIN: Thank you, Heidi.

Next slide, please.

My name is Mariko Geronimo Aydin. I'm also here with Onur Aydin, and we are the founders of Lumen Energy Strategy. We are EPIC-funded with a mission to help advance resilience planning in the state. Onur and I are very excited about the work we're doing to support demand forecasts, so thank you for that and thank you for having us here today.

We're here to give you a tour of how the hourly climate projections from the climate science community are translated into workable inputs to the demand forecast models and a bit on what we've learned in that process.

On the next slide, like the Amish barn raising you see in the background, I cannot talk about this work without also talking about the community and the collaboration process behind it.

Firstly, we are standing on the cumulative work of several EPIC projects and of many IEPR cycles and demand forecast cycles where each time the study teams involved made a critical advancement that brought us to this point. And for this IEPR cycle in particular, I want to thank everyone who has been working both in front of the scenes and behind the scenes to enable and support this work to bring climate science theory into this extremely important application of demand forecast.

And what's exciting about this demand forecast work the CEC is doing is it's the first of its kind. I am personally not aware of anyone in the U.S., at least not in the public domain, who is using climate projections at this spatial and temporal granularity to produce long-term demand forecasts at the state level. And it wouldn't be possible without the level of collaboration and knowledge exchange that's happening right now amongst many parties.

Next slide, please.

So for this IEPR cycle, we needed to figure out how to translate the data into the specific metrics needed for demand forecast. We needed to figure out how to adjust the demand forecast models to ingest almost 200 times more data, and even more for future IEPR cycles, and then fit the pieces together and see if it makes sense. So Onur and I will talk about the data inputs and then Nick will talk about the demand forecast model and results.

So we'll provide you a brief overview of the climate data sources, talk a bit about bias correction, and provide a refresher on our temperature detrending method, and then we'll show you some results for hourly temperatures. Also hourly dewpoint and cloud cover metrics.

Next slide, please.

This is a summary of the new downscaled climate projections data. It's a summary through the lens of what we need for demand forecasts. And if you're not familiar with the downscaled projections or climate scenarios, please do take a look at the links below when you get a chance.

But in summary, UCLA and the Scripps Institute of Oceanography and many other researchers have brought to all of us the latest and greatest global climate model results to a fine spatial and time granularity specifically for use in various adaptation and mitigation efforts in the state. The data have been released in three waves, and they're based on two types of downscaling models which I'll refer to as the WRF and LOCA2 models.

You can see the models vary in terms of the volume of data they provide versus the granularity of data. WRF outputs tend to include fewer runs with a focus on the mid-high climate scenario, 3-7.0, but at an hourly timescale. And then the LOCA2 outputs are a higher volume of runs across multiple climate scenarios but with a daily timestep.

Demand forecasts need hourly inputs, so that's an important consideration for us. Also the timing of data release, along with the IEPR cycle and the integration of the data into the state's toolkit, which we are downstream of, is important. So we rely on the four initial WRF runs you see here, released in late 2021, early 2022, and those are all now integrated on the Analytics Engine platform.

And as we digest the data, the annual patterns, the peaks in temperature affecting peak demand, and the hourly patterns, they have to have some coherence with the historical observations we have. And I don't mean they need to replicate historicals, but biases in these types of statistics, in particular, those will propagate through demand forecasts. So that's what we've had to look out for.

On the next slide I wanted to talk a bit about bias corrections.

Next slide, please.

Thank you, and thank you to the stakeholders who have opened up dialogue about this.

Bias is one of the main concerns when working with global climate projection. The global climate models, for example, some of them can be known to run hot or run cold. That's just one example of bias. But more generally, assuming the global climate models are particularly good at capturing the climate signal or long-term trends, which is what they're designed to do, bias can be anything in the data other than that, that systematically deviates from what you think is the population of possible outcomes.

So I have many cautions about bias correction, and this topic always teeters over the deep end of statistics, but for today I'll just say one thing, and that is: every time you manipulate the original climate projections -- which has to be done for real-world applications, we can't avoid that -- but every time you do that, you risk adding a new layer of modeling uncertainty that can skew your results, and you risk obfuscating the original information the climate projections were trying to convey, such as novel weather patterns you can't find in the historical records. So we try to rely on the climate science community to make those adjustments as much as we can, and we only make additional adjustments if it's absolutely necessary for our application. But otherwise try to keep the data as-is. That's our general approach.

Our main vehicle for bias correction is a localization model that brings grid cell projections down to the specific weather stations needed for demand forecast, and it uses historical weather station observations to do that.

That model's been around for several years. It is open and available on the Analytics Engine platform. But it is a work in progress, and we have seen some residual bias at a few stations and in some parts of the hourly profiles. Residual bias can be driven by the localization model itself, by the quality of station data that's feeding into it, or carrying over from the climate projections.

There's no localization model for dewpoint and cloud cover, which we'll talk about later. So those are subject to biases that may flow from the original gridded climate projections.

And the last thing I'll say on this is usually you'll see bias corrections work off of means, or medians, or trends, but for extremes, like extreme temperatures, where you don't have many historical observations to develop a clear picture of the population of possible outcomes, there are inherent challenges to bias corrections, and limitations.

So with all of that, I'll hand it over to Onur to talk about our detrended temperatures.

MR. AYDIN: Thank you, Mariko.

So I would like to start with a recap of temperature detrending method and our motivations behind it.

We discussed this during the IEPR workshop back in August so I will try to keep it brief. The better inputs are essential parts of energy demand forecasting where we need to understand really what can be expected in a typical, normal year, and also the range of potential outcomes that can happen in a given year. The challenge is that we now have evidence, very strong evidence, that both the normals and the distribution of outcomes, especially extreme events, are changing. They already changed to some degree as we speak today, and they have the potential to change even more at an accelerating pace. The weather normalization previously relied on historical data is no longer sufficient to capture these changes.

The latest and greatest climate projections have much better information on future weather risks than the historical record, but year-to-year variability is typically intertwined with the climate signals and the long-term trends. So detrending really retains all of that original information in the climate projections that we're working with, but it separates that year-to-year variability from the climate signal.

So through detrending we increase the ensemble of climate simulations by using a rolling window around each forecast year and adjust that data to better reflect expectations of the forecast year, which is in the middle. And we apply this approach, the de-trending approach, at the hourly station level to develop over 200 variants, where each variant is an 8760 hourly time series for each of the forecasts here. So in terms of the data that's been integrated into the demand forecast, it's an order of magnitude larger than the historical data that's been previously shown.

We account for the variations of climate trends by location and also by temperature levels, as we see different trends at different temperature levels, so we account for that. And at the end, we maintain hourly chronological order, which is really important because you need that to preserve the correlations of weather events over time, and also between temperatures, which is a key input, and other variables used for demand forecasting like dewpoint and humidity.

So for more details, you can check out our presentation from the August IEPR workshop. So we provided a link here. But with that, I want to just move to some of the results.

So next slide, please.

So I want to start with the projected cooling and heating degree days, the CDDs and HDDs, based on the detrended temperate library that we developed. And we benchmarked the results against the historical record.

The CDDs and HDDs are key inputs to energy consumption forecasts. They indicate how cold or warm outdoor temperatures are relative to a threshold at which cooling and heating needs are minimal, typically around 65 degrees. And the higher the CDD value is, the more energy would be needed for cooling, and the higher the HDD value is, the more energy would be needed for heating.

So looking at the historical observations on the charts on the left, you can see a very steep upward trend for CDDs and a steep downward trend for HDDs. These are consistent with the general warming of temperature levels.

So using the historical data without accounting for such trends would significantly understate CDDs and corresponding cooling-related energy usage, while it would overstate the HDDs and heating-related energy usage. Projected CDD and HDD metrics based on the trended temperature library addresses this issue. This is particularly important for resource planning because at the end, it directly impacts how much clean energy California needs to invest in order to meet future GHG reduction targets.

So looking at the projections, you see that the projections not only align well with historical trends and variability, but they also allow for a far more detailed look at the range of potential outcomes in a demand forecast year. So the charts on the right show the estimates from each of the 204 weather variants that we developed shown in gray circles, like little dots, and the corresponding normal level that we identify based on median values. You can also see how the ranges between, you know, 10th and 90th percentile levels will change over time.

So here I also want to highlight that these results are derived bottom-up from the hourly detrended climate projections, which is important because it promotes consistency in integrating the climate signals across various models for demand forecasting. Annual consumption, peak forecast, and normalization models can all use the same set of weather inputs and variants.

And the data library is also structured to support hourly demand forecast models and stochastic analysis in the future IEPR cycles.

Next slide, please.

Another important metric is -- well, the metrics of our hottest and coolest temperatures that you see around the year, as they are the key drivers of heat demand and associated system capacities. The recent heat waves in California highlighted the importance of characterizing extreme weather events, especially temperatures, in demand forecasting and grid planning. And historical record is useful, but it provides very limited information to differentiate a normal year from the extremes that can be expected going forward.

So the charts here on the left show the frequency of the top five hottest days of the year based on historical record. And looking at the distribution of those heat events over the last 30 years versus 20 and 10 years makes it very clear that the temperature patterns are already changing. So on the one hand you need a long enough history, like 30-plus years, to properly characterize the variability, but the historical record from decades ago is not reflective of what can happen today.

On the other hand, you want to rely more on recent data -- the last five, ten years -- to better reflect today's expectations when you look at a base year 2023 forecast. But the data is too scattered and not sufficient to come up with a reliable distribution of outcomes, especially for extreme events. So the detrended temperatures developed using the latest hourly downscale and localized projections can provide a richer distribution of outcomes, outcomes that are consistent with the underlying climate signals that are modeled by the climate scientists.

So looking at the charts on the right, you see the distribution of the same metric, the temperatures over the five hottest days of the year, based on 204 variants for each year. So each chart shows about one thousand data points here.

So you can see the distribution for the base year, 2023, and how that distribution shifts over time by 2035 and 2050. So these are shown as examples, but we basically have repopulated the variance for each forecast years between 2023 through mid-century, 2050. So the difference, you know, when you look at charts, the difference is only a few degrees, which could be hard to see unless you really look at it very closely. But a few degrees of difference is the difference between one-in-five-year versus one-in-two-year events, or one-in-30-year versus one-in-10-year events. So that difference is really significant for the purpose of system planning.

Next slide, please.

So last about the temperature-related metrics, I want to talk a little bit about the hourly shape.

The hourly shape of temperatures is becoming increasingly important for demand forecasting. That's partly because it impacts the hourly demand profiles at the system level and across planning areas, and how coincident or not coincident they are. But it also impacts the contribution of intermittent renewable generation toward meeting hourly demand, and the corresponding net peak load and the system ramp peaks that might be critical considerations for system planning.

So here we show the base year 2023 median temperature profiles developed using the detrended method, and we compare those results against the historical record.

So the results are very encouraging. At the planning level, you can see for each of the three IOUs here the results generally line up well with the historical data, where most of the difference can be explained by historical trends or variability. But through the process we also identify some residual biases in some of the hourly localized station-level projections. So for example the night temperatures, especially in winter, tend to be a little warmer than expected in the projections. We've also seen a few of the weather stations are so close to the coast where it requires extra steps to make sure that the gridded projections used for localization are not in the ocean, or some of the stations where historical record use for localization is incomplete for some of the earlier years prior to 2014.

So overall the next steps would be to make further refinements to the localization method to address these remaining biases and improve the characterization of hourly what's used in demand forecasting.

So, with that, I'll pass it to Mariko.

MS. AYDIN: Thank you, Onur. This is Mariko.

Next slide, please.

Dewpoint. Dewpoint is a necessary input to the hourly demand forecast model. Dewpoint is an indicator of the air's absolute moisture content. So in that regard, high dewpoints are a better measure of human discomfort than something like relative humidity, which can be high even at low temperatures. Dewpoint is not an output in the WRF or LOCA2 models, but it can be derived from temperature and relative humidity, and there's no localization model currently available for dewpoint.

So what we did is we derived dewpoint from the detrended temperatures and the relative humidity at the closest three kilometer grid cell to each station. And we do this calculation for each of the 204 weather variants corresponding to each demand forecast year, and then at each weather station. And this calculation preserves the physical relationship between the projected relative humidity in the area and our detrended temperatures, and we're applying the same formula as used by Cal-Adapt.

On our last slide, the next slide, we have cloud cover. This is another necessary input to demand forecast.

This was more difficult to derive from the climate projections, but we did come up with an approach that performs surprisingly well. The results are in our appendix slides. Cloud cover is also not an output for WRF or LOCA2, at least not at the level of granularity we need, and there's no localization model for it.

WRF and LOCA2 models, they output various metrics on solar insulation, which could be a good substitute, but remember the demand forecast models are trained on the historical relationship between weather metric and demand. So for demand forecast, we really need climate projections metrics that are also in the historical record or can be reconstructed for the historical record.

We estimated an hourly multinomial probit regression model for cloud cover to capture the historical statistical relationship amongst cloud cover, other available weather metrics, calendar effects such as month and hour, and location. And to do that, we used a separate multinomial probit model for each weather station with explanatory variables including hourly precipitation, 24-hour precipitation, relative humidity, a two-part temperature spine, and indicators for month and hour. And then the probit model results are then applied to the downscaled GCM data at the closest three kilometer grid cell to each station, and then we map all of that information back to the temperature variants based on the GCM run and the year.

So if you're curious about that model, please take a look at our appendix slides. Let us know if you have any questions.

That's the end of our presentation.

Thank you for your attention, and we're happy to answer any questions you may have.

COMMISSIONER MONAHAN: Vice Chair, we can't hear you.

I think maybe you're on double mute.

VICE CHAIR GUNDA: Thank you.

I was on double mute.

Did you want to kick off?

COMMISSIONER MONAHAN: I was hoping you were going to lead this one, Vice Chair Gunda, because this is pretty sophisticated modeling, and I have got to say my head is spinning.

I actually had really basic questions.

But so maybe actually I could start with a basic question --

VICE CHAIR GUNDA: Yes. Totally.

COMMISSIONER MONAHAN: -- and then you could go actually with a sophisticated question.

But I'm curious, like, how much difference does it make in terms of our electricity use -- or peak electricity use, I guess -- when we're taking into effect things like cloud clover and dewpoint? I just -- for the unsophisticated among us who are learning this, like, how much of a difference is this making in terms of the actual peak demand? Or could this make, you know, when you're looking at kind of the range, the extremes?

MS. AYDIN: Thank you for the question. This is Mariko.

So in terms of dewpoint and cloud cover versus temperature, temperature is definitely the most dominant explanatory variable.

I'm not sure -- I don't think Nick has in his presentation the exact, you know, relative magnitude of each, but in his presentation, he will go through aggregate results and impacts on the peak forecast versus the methodology.

COMMISSIONER MONAHAN: I have to say, though, I'm going to be in a meeting from 1:30 to 2:00, so I hope I don't miss that piece.

MS. AYDIN: Oh. Okay.

COMMISSIONER MONAHAN: But I was curious about it, but okay.

VICE CHAIR GUNDA: Commissioner Monahan, I think one point just to kind of consider, like -- so when we had the 2022 crisis, right? So one -- we're tracking two things. One is, you know, what is going to be the system hourly load that the CAISO is going to see, and that is the composite of consumption minus behind-the-meter generation. So and then you're also kind of trying to match on the other side.

Specifically on cloud cover, which was a significant point of concern for the legislature, you know, we had monsoonal conditions coming out of the 14th and 15th. So if you look at August 17th, 18th, we had monsoonal conditions, and we had the significant drop in solar production in front-of-the-meter on the bulk side. But that was also, you know, kind of accentuated by a significant drop in behind-the-meter solar production, and then my recollection based on some data was, like, it's in the thousands of megawatts that we saw kind of a shift because of the cloud cover in behind-the-meter.

COMMISSIONER MONAHAN: Wow. So that's really significant. Right

VICE CHAIR GUNDA: Yes.

But Nick might have more accurate numbers based on where we are today. Back in the day, we were trying to, you know, stitch together some back-of-the-envelope calculations to answer some questions coming from the legislature.

So Nick, I don't know if you have more pointed answers on the cloud cover impacts.

MR. FUGATE: No, not on the -- so I just -- Commissioner Monahan, that's a great question, and one I was not expecting to speak to, but I'm just quickly here pulling up our regression statistics.

And just to -- you know, I can give sort of a sense of the magnitude. Temperature is clearly the biggest driver for peak load and so, you know, just looking at our regression results for, you know, PG&E for example, for '19, for a single-degree increase in temperature, we're looking at, like, an increase of 120 megawatts whereas with dewpoint it's much less impactful. So, you know, for every incremental increase in the dewpoint metric, we're looking at a 25-megawatt increase. And also the dewpoint statistic is over sort of a narrower range.

So generally as we're performing the simulations temperature is by far the biggest driver, dewpoint less so, but both -- and cloud cover even less so -- but both have, you know, predictive power in our model.

MR. AYDIN: Can I add one more thing?

I think, I mean, definitely temperature is the biggest kind of driver of demand, and then cloud cover affecting the behind-the-meter solar generation is probably the close second today.

But I think to some extent, the dewpoint not in all hours of the year, but the times when the temperatures are high and also the dewpoint and the humidity is high -- that combination in a small subset of the hours can really affect the impact of the felt temperatures. So I haven't really looked at the exact impact in terms of, like, a total like megawatt, but I know that it's definitely -- as Nick said, it has a predictive power, and that predictive power is more pronounced during those kind of peak extreme hours when the temperatures are high as well, so.

That's a really good question.

COMMISSIONER MONAHAN: Thanks, that was really helpful.

VICE CHAIR GUNDA: Thank you, Commissioner Monahan. Thanks for setting that up.

I don't know if I have any more stuff to say here, but I have some questions.

But before I go to that, Commissioner Shiroma, it looks like you have a question. Please go ahead.

COMMISSIONER SHIROMA: My question is this, and I appreciate that we are substantially looking at the peak modeling, factoring in bias, what have you, but for the cloud cover piece of this, during the time when solar is being relied upon heavily, especially in the future, and if you've got cloud cover, it drastically impairs the efficiency of the solar. So is that something that we look at in the future?

Only because, you know, that the peak solar doesn't coincide with the temperature.

But is that a next -- is that kind of already factored in, or is that kind of a next phase in terms of just efficiencies of the DER, AKA solar?

MR. FUGATE: So maybe I'll speak a little bit to that. It is a question that we have been grappling as we're thinking about our load modeling process.

So, you know, we are bringing PV generation into our process in multiple dimensions. One is, you know, in the historical process as we are attempting to estimate our models. So what we're actually modeling is really a counterfactual estimate of consumption, right, which we don't have actual recorded values for. What end users are actually consuming in total, regardless of how that demand is being served.

And so to get to that, we are actually bringing in our best estimate of what actual PV generation is happening. So in the historical record, we have cloudy days that will reduce the generation -- behind-the-meter generation that we are adding to the system load data that we have to come up with that consumption number.

So that's one way that we're trying to address the impact that cloud cover can have on solar generation and thereby on load.

In the forecast period, what we have traditionally done is use a normal or sort of average solar generation profile and decremented our forecast of consumption using that normal profile. And I'll speak a little bit more about this in my presentation, but that sort of reduces the variability that you would perhaps expect to see in the forecast period, because, you know, a normal profile is -- and I actually do have a specific slide on this, so I'll try to be brief now -- but a normal profile is not going to reflect those types of days where you have reduced PV generation due to cloud cover.

So when I say that cloud cover has a low impact in our modeling, that's, you know, I'm sort of -- that's because we're modeling consumption. So if we were, you know, if we were to -- and one of the things that we're looking to do in future cycles is find a way to reflect that variability that you would expect to see in behind-the-meter solar generation and the resulting impact on demand profiles.

So that is a key question, so thank you for asking.

COMMISSIONER SHIROMA: Yes, thank you. And that'll factor into future, you know, rate design.

Thank you Nick, and thank you Vice Chair.

VICE CHAIR GUNDA: Thank you Commissioner Shiroma.

I have just a couple of comments and a couple of questions.

So first I think Mariko and Onur, thank you so much for the presentation. I mean, I can't tell you how excited I am as you guys are working through that stuff. Just, you know, the amount of effort that's going in. And Mariko, I also just appreciate you really recognizing the group effort.

And then I want to just commend the CEC team and all of the work that they do in really just bringing this together. So really, really appreciative of the presentation.

I have a question first and then maybe another comment.

If we go back to slide number seven real quick. Like just from a visual perspective on slide number seven, I think especially on the HDD side, it seems that kind of the distribution gets narrower as you go down into the later years. So the spread's higher in the near term, and as you go, you know, longer into the future, it's just -- is that just, you know, what do we -- is that first of all real, the -- kind of the narrowing of the temperatures? And if it's yes, then kind of like what do you attribute that too?

MR. AYDIN: Yes, I think it's not this slide. It's slide seven of, I think, our slides.

Yes, maybe a couple more.

Next one.

Yes.

This slide, right?

MR. AYDIN: Yeah. So, I mean, we've been really looking into that. That's a great question.

So I mean one reason for really looking in -- developing the weather variants for each of the years to really get a kind of an insider view of what can happen in a given year, the variation, having more data points on how that can kind of evolve over time, you know, with the expectation that it might -- the variation might grow, or it might just stay constant.

When I look at it, I don't see the variation shrinking as much. My read is that, given the four WRF formulations that they've used for this cycle and the detrending approach, that it really translates into around the medium levels a variation that seems to stay relatively constant.

And again, I mean, I think that might be just an outcome of using a more modest emission scenario. We used SSP3-7.0. I'm sure there are other emission scenarios where when you really look at the potential outcomes, when you go up to the mid-century, that the variation might really go much higher, recognizing that uncertainty. But that's something that hasn't been really considered for this cycle. We focus on a specific emission scenario.

VICE CHAIR GUNDA: Yeah, maybe this is something I follow up.

But let me ask you -- let me kind of share with you where it's coming from, the question.

So one is kind of how do we deal with the median and incorporating that into a planning on the supply side, right? So the IRP is going to tee off of this.

Second use case for this is really around developing what an extreme scenario we need to be prepared for on the grid in a given summer. So my lens of this is how do we make that 90th percentile or 95th percentile that we need to kind of keep an eye on?? And kind of want to understand is it essentially going to follow the same trend or it's going to widen or tighten over time, right?

So that's kind of the question, where it was coming from, but if we have any quick response, but if we can follow up.

MR. AYDIN: Yes. I mean, I think, you know, that's a great question. I mean, I think the question is great.

I think one challenging aspect of that is when we think about extremes, you know, 95th or 90th percentile. You know, it's one thing from energy perspective, you know, it might mean something versus from a peak perspective, it might be a different -- there's so many different dimensions of the weather inputs going into the demand. Like, what is really normal and what is extreme? It's really multidimensional.

And I think that's why we were trying to set this up in a way that, you know, we have specific variants, we call it weather variants, so you can kind of keep track of that variant and the corresponding implications for CDDs, HDDs, and corresponding impacts on peak temperatures and, you know, in the future, like, the electrification -- if cold temperatures become also more important, that you'd be able to track all of that metric for each individual variant.

My guess is like for this IEPR cycle, and as Mariko said, we were somewhat limited in terms of what we could incorporate, just because of the timing of the climate data that became available, and the timing of the IEPR. So we use four simulations and then just like really stick with it.

But, I mean, I think our aim is to really extend that analysis and look at really a broader range of the additional WRF simulations that are dynamically downscaled, and then also some of the local runs Mariko mentioned. Just to see, as you mentioned, kind of a closer look at the extremes, and how to really pinpoint like the extreme that needs to be considered for persistent planning.

It's something in our radar, but it doesn't necessarily show up in this slide.

VICE CHAIR GUNDA: Yes. Thank you.

I know there's a few questions coming up, and some of those questions are along the lines of this discussion, so I want to end it that way.

But just kind of one closing thought is I want to completely recognize kind of the interrelationship with the distributions of -- whether it's temperature, whether it's kind of the consumption -- all of this is kind of connected in a more complex way.

I would love for us to continue to think through, how are we standardizing the weather variants, you know, consistently across CEC and PUC processes, right? So we have that visibility of what we are doing here on the demand forecasting either translates, double counts, or is not captured, right? And how do we do that? So I'll just put that as a flag for us to think through.

And for me kind of one of the things that we can immediately kind of work on is, especially given the reliability concerns, how do we translate some of the results from here into potentially thinking through -- even qualitatively, right -- in the near term, on how do we think about the extreme weather events and, you know, making sure that we have enough, you know, resources during those times.

So anyway, again, I just wanted to flag that.

Thanks to Heidi and Nick for their excellent leadership internally, and to both of you, amazing presentation. I look forward to continue working with you all.

With that, I'll pass it to Heather.

MS. RAITT: Great, thanks. So Heidi is going to moderate a couple of questions. I don't know that we have time to do all of them, but let's see what we can do.

MS. JAVANBAKHT: Yes.

So this is probably a question for Nick. The question is from Mark Jimenez at PG&E. How can the IEPR be broken down to reflect coastal, interior, and mountain climate differences?

MR. FUGATE: Broken down, so I suppose that's a question about disaggregating our forecast.

And this question -- so right now we have weather stations, right, that we are waiting to come up with a single set of weather statistics for each of our forecast zones. To some extent those forecast zones are coastal and inland, but our hourly analysis is sort of -- at the moment, we would have a challenge to break that down further than our planning area. And that is because the hourly loads that we use to estimate our models are the CAISO EMS data, so that is at the system level.

So really, in theory, we could go down to forecast zones without too much additional complication, provided we had hourly data to estimate our models. So perhaps that is a discussion that, you know, could translate into the AMI data space, so potentially a use case there if that is a need or would be valuable.

MS. JAVANBAKHT: Thanks, Nick.

And we have one other question to answer live for

Lumen.

So on slide 8 of the Lumen presentation, why does the 2023 distribution not have a 108-degree observation? And this question comes from Carrie Bentley at Gridwell Consulting.

MR. AYDIN: Yeah, I mean, I think that goes to the importance of the extreme, very extreme events that Vice Chair Gunda was just referring to.

I think it's -- one thing to clarify on that chart is the scale is different. The historical data, because it's somewhat limited, there's only one observation of 108 degrees in the aggregate CAISO metric. And with historical standard, it's a really, really extreme metric that doesn't seem to be captured in the climate simulations. Like, so, you know, looking at the four simulations and at those -- the window of different years to capture the variability, it looks like, you know, we either don't have or a somewhat limited representation of that level of extreme. And again, that's something that is definitely on our radar.

I don't really think that, you know, necessarily impacts the overall grid planning, which tends to kind of just like aim for like, you know, a one-in-10-year kind of load standard from a resource planning perspective. The 108-degree was based on historical standards and also on the projections. It's a far more reaching kind of event.

Having said that, I think it's something that we definitely want to investigate more, especially with the new data, the new simulations that have become available. We want to look and see if there are more extremes available in those climate simulations.

MS. RAITT: Alright.

Well thank you Heidi, and thank you Onur and Mariko. Appreciate your presentations, and unfortunately we need to move on.

So next we have Nick Fugate to present the results of the forecast.

So go ahead, Nick.

MR. FUGATE: Thank you.

So good afternoon, everyone. My name is Nick.

I'm going to be talking about the hourly peak electricity demand forecast, particularly some of the changes to our process that we have tried to implement for the 2023 cycle.

So as Heidi mentioned, this was a challenging cycle in general. You know, we debuted some new models, which were discussed at earlier workshops. We've added some fantastic new staff and some new and important datasets, and all of this is very exciting. But it added a lot of additional work to our process, which is part of why we are here so late in the month. So I just wanted to thank everyone again for taking the time to be here.

Next slide.

So the Energy Commission's peak forecasts are used as a direct input into resource reliability and transmission studies as Heidi mentioned. Similar to previous cycles, our forecast team has assembled two specific scenarios -- the planning forecast and the local reliability scenario -- that I'll be referencing in this presentation. So we've discussed those previously.

Heidi mentioned that the key difference this year is around the CARB rule being implemented in the planning scenario this year, not just the local reliability scenario. So there's a -- and also Heidi mentioned that there's a single forecast set agreement between CPUC, CEC, and CAISO. So that agreement evolves year to year. It's memorialized each year in the IEPR.

My presentation is mostly going to focus on our hourly modeling process. Most of the use cases for this work focus on peak system loads. These though are derived from our hourly forecasting process.

So at a high level our hourly load model, or HLM, has three broad steps to it.

First we develop a base load consumption profile, which is meant to reflect reasonable levels of load for every hour of the year under normal conditions, and to also reflect realistic patterns within days, months, and seasons. That's based on current conditions as the system and as customer behavior exists today.

We then apply that profile to our annual consumption forecast, or rather to a version of our annual forecast that has the effects of specific load modifiers removed. And that's because in the second step we account for those load modifiers separately because each of them has their own distinct profile. We then layer those load modifier profiles onto the base profile to complete our hourly forecast.

And then as a final step we calibrate the base load profile, scaling and shifting it slightly until the resulting peak value in the first year of our forecast aligns with our weather normal estimate of the most recent summer peak.

Next slide please.

Our hourly load model has been largely unchanged for the last several cycles really. This year we attempted to rebuild many of its component pieces. This is in part to respond to stakeholder needs and in part because we had new data and analysis which enabled some of this work, and also in part our hands were simply tied by staff turnover. So this rebuild was a good opportunity for new staff to become more intimately familiar with the model.

In any case, we had a few high-level objectives in mind this year.

First and foremost, we wanted to ensure that we were well positioned to use all of this new climate modeling analysis that Lumen just described. Our EPIC grant recipients -- Lumen, Eagle Rock Analytics, and others -- have been just incredibly supportive in providing analytic and data products that are well-suited to our forecast. We wanted to use what data we could for this cycle, but also take steps that would help prepare us for additional work next cycle. And I'll talk a bit more about this later.

Second, we wanted to update our base consumption profiles. These should represent some reasonable patterns but, you know, without a refresh of the profiles. They have drifted away in recent cycles from historic patterns and some key regards.

The third point we had in mind was to support the development of data sets for stochastic system modeling. Our hourly forecast is intentionally designed to be pretty normal. This is useful in many types of studies, but some system reliability studies need to consider a much broader range of possible load patterns. So one of our longer term objectives is developing distributions of hourly load profiles consistent with our forecast.

Next slide, please.

Creating a weather normal estimate of peak load is the last step in our process. But it's also the starting point for the forecast. So I'm going to start with it.

Next slide.

We calibrate our hourly forecast to the most recent year of historical peak load. But peak load is highly sensitive to temperature and our hourly forecast assumes normal conditions. So it's important that we not calibrate our results to an extreme load event. 2022, for example, was a record-setting summer for peak load. 2023 was actually quite a mild summer. I was thinking this back in September, but I didn't want to say it and tempt fate. But at this point in the year, it's probably safe to call 2023 a mild summer.

Now, if we had calibrated to either of those actual peaks, our forecast would have been skewed high or low, respectively. So instead we need a counterfactual estimate which takes into account the observed load response to temperature, but then assumes normal peak weather conditions. And to illustrate this point, I've plotted daily peak load against a weighted average of temperature statistics for San Diego Gas and Electric.

Here, the slope of the clusters of data points for each year would give some rough intuition around the load response to temperature in each particular year. Generally, the 2022 data points are higher than 2021, which are higher than 2020 throughout the temperature range. So you might look at this and expect the normal peak estimate to be increasing each year in that window.

Next slide.

Before I talk about what we're doing differently, let me outline our existing process.

We start with hourly system loads from CAISO and we add to that estimated impacts of load reduction events. These could be called programs, or voluntary conservation during flex alerts, for example. These estimates come to us from the IOUs and CAISO. We do this because dispatchable demand response is considered on the resource side of the balance sheet, and so we don't want to double count by embedding those impacts in our forecast as well. And for weather data we use a number of weather stations located across the state that we weight to create a single set of daily statistics for each planning area.

Once we have our counterfactual loads, we select the peak load for each day of the last three summers, and we regress those against weather effects such as maximum and minimum daily temperatures and calendar effects like day of the week and month. We do this to establish the current load response temperature and then we use that regression model to simulate peak loads using historical weather data from the last 30 years.

It's during that simulation step, as I mentioned previously, that we have typically, I guess, in order to account for climate change absent this type of climate data that Lumen just discussed what we have done in previous cycles to kind of account the climate trend is during the simulation step we have sampled more recent historic weather patterns more frequently, so sort of adding a recency bias to the simulation step.

And from the resulting set of simulations we take the maximum values and we select the median value for those maximums as our normal estimate. So that is the process as we have been implementing it in previous models.

Next slide.

This cycle, though, we have implemented some changes. We transitioned from using historical weather patterns to the synthetic climate variants that Lumen discussed earlier. This was something of a priority. We've been discussing for several cycles now some of the limitations of using historical data to simulate loads in the context of a changing climate.

We've talked about using an abbreviated

historical window, but that has problems, as Onur noted in his presentation. You miss decadal patterns. You don't have as much confidence in the resulting load distributions. On the other hand, this climate data offers us 204 weather patterns meant to reflect present-day conditions.

We also moved from a daily peak model to a set of hourly models. We looked at the recent historical load record and identified the hours where the daily peak load was likely to occur, and then we developed and estimated a model to predict load for each of those hours individually. Then the maximum daily peak is just the maximum of the individual hourly predictions. And the idea here was to reduce the confounding effects of behind-the-meter solar, which varies significantly across months and hours within the peak window. But it also allowed us to introduce other explanatory variables, such as dewpoint and cloud cover. Doing so brings the weather normalization modeling process more in line with the predictive variables that we are using in our hourly load modeling process.

In general, these individual hourly models perform better than the single daily peak model that we have been using previously.

Next slide.

So here I'm illustrating the distribution of daily max temperatures for each IOU planning area, comparing specifically the distribution implied by the last 30 years of history against the distribution implied by the climate variance.

Median values increase for both PG&E and SDG&E, not so much for Edison. But this is just one statistic and the same chart for daily minimum temperatures, which also has predictive power in this analysis, it shows an increase across all three territories. And this is in line with what we have observed historically with recent minimum temperatures: daily minimum temperatures increasing at a faster rate than daily maximum temperatures.

Next slide.

And I'm sorry. There is a mistake on this slide. I recycled this one from last year's presentation, changing the numbers on the table. But that note at the top, giving weight to more recent weather years, that no longer applies. That was from last cycle.

Anyway, the table is the key feature here.

So showing the results of our peak normalization process for CED 2023, planning areas are identified in the first column. The second column has the actual system peak for summer 2023, with the caveat that we've added load response impacts to the CAISO's load history. That third column is our normal peak estimate for 2023. Again, 2023 was a relatively mild summer, so directionally these values make sense. The fourth column is our estimate from last year, and the last column is the percent change between this year's estimate and last year's. So despite the significant methodological changes, there were not actually at a hugely different level.

There are a couple more advantages that stem from this change. One is that it should be more consistent year-to-year. That is, the change in peak load will come more on the model estimation from the apparent changes in load response to temperature. So the changes will come from that rather than the addition of new weather patterns for simulation. So under the previous process, we were using a smaller number of weather patterns, and each year we are adding new patterns, the addition of an extreme weather year can change the sort of implied distribution, especially when we were weighting more recent years more heavily.

Let's go to the next slide, please.

And one additional benefit is that under this process we can speak a little more confidently about the distribution of peak loads. So this table shows the 1-in-x peak factors that are implied by our CED 2023 normalization analysis. And what I mean by this is these are the multiplicative factors that we could apply to our annual normal peak forecast to get, for example, our one in five peak forecast, which is the peak load you would expect to exceed only once every five years. For each planning area, I'm showing two sets of factors: the existing factors that we've been using for a number of cycles now, and the new factors implied by this analysis.

So across the board, both PG&E and SCE have higher peak factors. SDG&E are actually a little lower, but these factors are relative to the median expectation. And so, you know, you might recall from the distribution I showed earlier that, you know, SDG&E had the greatest increase in median values. So that is one thing to keep in mind here.

So these new factors could be applied when we finalize our set of peak forecasts, and we would welcome any stakeholder input on that point specifically.

Next slide, please.

Okay, so moving on to the hourly model itself.

Next slide.

This is about the highest-level overview I can provide of our process as it has existed for the last few cycles. Fundamentally the concept is similar to our weather normalization approach. The input data sets are similar. Demand response is added to system load. In this case though we also add estimates of behind-the-meter PV because what we're modeling isn't system load but actually hourly consumption.

The model predicts consumption ratios as a function of weather and calendar effects. We have an individual model for each planning area and hour of the day, which we've typically estimated with five years of load and weather data, the weather data being temperature, dewpoint, cloud cover. And having estimated these models, we then use them to simulate consumption ratios using historical weather patterns. At this point, we have 22 historical weather patterns. We also artificially cycle through days of the week for each pattern, just so that we're not obscuring the effects of a particularly hot day by having it fall exclusively on, for example, a Sunday.

Then for each simulated year we rank-order the ratios and across all years we select the -- I'm sorry. Across all years we select the median ratio from each rank. So that gives us a normal 8760 load duration curve, and then we assign those values to specific hours of the year based on ranks derived from averages of recent historical load patterns.

Next slide, please.

This year we rebuilt the model. The climate libraries Lumen discussed earlier, there are 204 hourly weather patterns specific to each forecast year over almost

20 forecast years. This is in contrast to just 22 historical patterns that we're currently using for simulation. So it's orders of magnitude more simulations, and on top of that the simulations would need to be structured differently with a unique set of patterns for each forecast year.

We're not currently using the climate data in the simulation step. We modified our models to be able to do that, and we have completed a run, sort of a proof of concept, but this is a significant change. We noticed some peculiarities that warrant further investigation, and we don't feel comfortable implementing it without further review both internally and with stakeholders. So this is something we will consider for next cycle, but we did do a lot of work with the framework in place.

A related change that we did implement for the calendarization step: where we're assigning consumption ratios to specific hours of the year, we moved from developing ranks based on historical averages to developing ranks based on simulated values. We view this as something of a necessary change. One of the primary benefits of using the climate data in our hourly modeling process is that we can have load patterns evolve over the forecast horizon consistent with evolving weather patterns. So not just reflecting, say, you know, average increases in temperature, but reflecting, you know, longer-duration heat waves, warmer shoulder months, et cetera. So using simulated values to do the calendarization allows us -- will allow us to do that, whereas using the historical loads in the calendarization steps sort of cements us into a single present-day pattern.

And finally, we have changed how we're considering PV generation in our counterfactual consumption history. Because we didn't have anything better previously, we had been using average profiles and adding those to system loads, but that poses some issues.

Next slide.

So this year we procured meter data for a substantial segment of California's behind-the-meter PV systems. This gives us some insight into actual generation on any given day. So in the chart here I'm comparing the normal estimate we had been using to reconstitute consumption and I'm comparing it to the levels of PV generation implied by the meter data. Generally the normal profile underestimates generation on most days slightly, but on cloudy days the normal profile significantly overestimates generation. So if we were to add the normal profile to system loads as we have done in the past on those cloudy days, we'd have huge spikes in counterfactual consumption. Using the meter data mitigates this issue, and that's actually one of the reasons we haven't updated our base load profiles in a couple cycles.

Next slide, please.

But with the update to our base load profiles, we see some improvement to one of the issues exhibited by our previous profile. So here I'm showing our average system load profiles for year 2022. One is from last cycle, CED 2022. That is our old profile. And then one is our preliminary updated profile for this cycle, CED 2023. And then we have one representing actual historical loads for year 2022. And again, these are average weekday profiles.

And generally the updated profiles produce net loads that are much more closely aligned with the historical values on average, especially in some key months. So you know CAISO had observed, for example, in the winter months, our evening peak was much higher than our morning peak, whereas, you know, in the CAISO system we have been seeing typically more comparable levels of morning and evening peaks.

Next slide, please.

This has implications for another key use case. Our hourly forecast service is an input to CAISO's Flex RA study, which examines resource needs to meet average maximum daily three-hour system ramps. CAISO has noted that the ramps implied by our hourly forecast far exceed recent historical ramps -- again, on average.

So this chart shows values from CED 2022 using all profiles are preliminary CED 2023 profiles, and then compares them to a history, all for calendar year 2022. You can see the exaggerated ramps implied by the old profiles, which are problematic for Flex RA, especially in the winter months. The preliminary CED 2023 profiles seem to mitigate this issue.

Next slide please.

So monthly peaks: another key statistic taken from our hourly forecast. These are used to set resource adequacy requirements. I'm showing our new preliminary peaks for year 2023 in contrast those with the CED 2022 forecast and with the last seven years of historical peaks.

A few things stand out here. Our preliminary forecast seems particularly low in the winter months and early spring. July stands out as slightly high, and October, while not necessarily unreasonable from a one-in-two perspective, is substantially lower than previously forecast. So we will be speaking with CPUC and CAISO. We've already initiated some discussions and we'll work to understand any implications from this.

Next slide please.

Moving on to load modifiers.

Next slide.

Recall that we are using the hourly load model to develop base consumption profiles without any impact on load modifiers. So that's what I'm showing here for select years. You can see the shape is relatively static over time, each hour increasing in proportion to our annual consumption forecast. We then layer on the impacts of load modifiers to get the resulting system profile, which is kind of the key output.

So next slide.

The system profile is not static over time. Instead, it evolves with the addition of load modifiers. In the interest of time and because they've been discussed at other workshops, I'm not going to go over each load modifier profile individually, but the most impactful modifiers are PV, which carves a significant portion of load out of the middle of the day. Fuel substitution adds substantial load in the morning and evening hours; EV charging taken together adds substantial load in the middle of the night and middle of the day. And as an appendix to this presentation, I've included charts sort of similar to this one but which show the evolution of impacts over time for each of our individual load modifiers. Fuel substitution and EV charging profiles are both relatively flat over the peak window, kind of leaving behind-the-meter PV to push the peak hour gradually later in the evening to hour 18.

Next slide.

So here I'm showing the impact of each load modifier on the peak day, isolated to hour 18. This is the impact in 2040 relative to the impact in 2022. Fuel substitution and electric vehicle charging together far outweigh the impacts of all other load modifiers. Everything taken together, these modifiers add nearly 20,000 megawatts to forecast system load in the planning scenario.

Last year -- oh, I'm sorry.

Next slide.

Last year, I noted specifically for the reliability scenario that the addition of fuel substitution impacts significantly increased the managed winter peak forecast by the end of the forecast period. That same point is relevant and this time with the changes to the planning forecast, including the CARB rule, it's relevant for the planning forecast as well as the local reliability scenario. So by 2040 roughly 15,000 megawatts of fuel substitution impacts are enough to push the February morning peak well over 50,000.

Next slide, please.

So my next few slides cover preliminary results, but I want to emphasize that these are preliminary where --

I'm sorry, I think we dropped a slide here. But that's okay.

So I want to emphasize that the results of preliminary were in the unusual position this cycle.

Typically by the time we bring results to a workshop we spend a lot of time with them reviewing them internally, dissecting those results, making comparisons, and performing various checks for accuracy and reasonableness. And with so many of the changes this cycle, the forecast took much longer typically than usual. And so we're running into our year-end deadline. We are presenting results here today and asking for stakeholder comments and review, but we are working in parallel internally to continue our own review.

So we'll be paying particular attention to alignment of all the pieces of the hourly forecast, and have in fact already found a slight issue, which is the slide that I dropped, with one of our transportation profiles being misaligned by an hour. So things like that will need to be corrected before the final results are posted for consideration for adoption.

So next slide, please.

Starting with PG&E, which is most similar to last cycle's forecast both in starting point and in growth rate, the timing of the peak hour is in line with recent historical peaks, hour 18.

The most notable difference here is with the planning scenario. Like we said, the additional fuel substitution places significantly more impact into the planning -- low growth into the planning forecast, narrowing the gap between the two scenarios, CED 2022 being the exception. This smaller delta between planning and local reliability forecasts is actually more in line with what we are accustomed to in previous cycles.

Next slide, please.

SCE is somewhat of a different case. While it starts from a very similar level, our preliminary peak forecast is occurring earlier in the day relative to last cycle's forecast. The earlier peak hour means that behind-the-meter PV is having a much more significant peak reduction effect in the first few years of the forecast. By 2026, peak hour shifts to hour 16, so this reduces the impact of PV, and with that and the rapid acceleration of electrification, we return to a period of significant peak growth.

Next slide, please.

SDG&E also starts from a similar level. The peak falls on hour 16 throughout the forecast, and this is earlier than you might expect looking at recent history. It's also quite a bit earlier than we'd previously forecast. There's not as much PV generation in hour 16 as there is in hour 15, so you don't see quite the same initial decline as you do with Edison, but it's enough to flatten the peak growth in the near term before electrification really takes off.

Next slide, please.

This is the CAISO coincident peak forecast, which starts at a lower level than previously forecast. And this isn't due to lower coincidence across three IOU TAC areas. Similar to the other TACs, the peak hour is earlier than recent history suggests -- hour 16 at the start of the forecast -- which again means that there's enough PV generation added in the first few years to speed growth.

As I mentioned at the start of this section, we're still reviewing these results internally, and as we do, these are two of the points that we'll be focusing on, both the timing and coincidence of the peak hours, particularly in the initial years of the forecast.

Next slide, please.

And from this point, in order to wrap up the forecast, we're going to docket more detailed data sets, including the full hourly files showing the full 8760 load and load modifier profiles. I'll include some summary files isolating just the peak hours and the peak days, since those are of particular interest.

And during the comment period following this workshop, we certainly welcome stakeholder feedback, and also staff can be available for more targeted discussions.

We will internally continue to review these results and address any issues we find prior to posting a final set results in January to be considered for adoption.

That's all for finalizing this forecast, but I also wanted to note that there are some additional changes we have in mind to make for next cycle, particularly related to incorporating the hourly climate data more directly into our hourly simulation process. But that is, like I said, a significant change and one that could take quite a lot of time to vet. Given the preliminary work we've done this cycle, though, we're well positioned to start that process early next year. And we've heard from some of the utilities that they're also working on this with the newly available climate data, and so this is actually a pretty exciting opportunity to share data and methods and experiences so far.

So my remaining slides are just an appendix, the set of load modifier impact profiles for reference. So I'm going to stop here and welcome any comments or questions from the desk.

MS. RAITT: I think you're double muted, Vice Chair.

VICE CHAIR GUNDA: Thank you.

My phone -- I'm trying to not make any noise. So thank you.

Nick, thanks for the presentation. I recognize that some of the results are in the draft, and look forward to checking in once you have engagement with the key players.

Just on a couple of things. We don't have to pull up the slide, but on the CAISO annual peak, for example, for 2023 and 2024, is it supposed to be month nine or month seven?

MR. FUGATE: It is month seven in our preliminary results. But again, this is one of the things that we're going to be looking at as we review the results, is that sort of issue of coincidence. So I want to make sure we fully understand why it's falling earlier in the year and make sure that we're comfortable with where that lands.

VICE CHAIR GUNDA: Okay.

So yeah, that's kind of definitely one of the quick visually.

And then you said, the CAISO annual peak, that the coincidences are changing, right? So can you kind of explain a little bit about where those changes have come from? Like what's -- is that historical changes in historical data? What's the reason we are seeing that,

that's such a significant difference in the coincidence?

MR. FUGATE: Yeah, so the coincidence in the early years is coming from our update to the base consumption profile, so that's what we want to pay particular attention to and make sure that that is reasonable.

And then as you go further into the forecast period, the coincidence does increase. That's driven just primarily by the sort of similar load modifier profiles being applied to all three TAC areas. So that's really driving the timing of the peak as you go further into the forest. But the initial coincidence is coming from the -- or the initial change in coincidence is coming from the update to the base profiles, and that's what we want to pay particular attention to over these next couple weeks.

VICE CHAIR GUNDA: Thanks Nick.

I think I kind of just to reinforce the slide 23, and really the usefulness of slide 23, just kind of giving a heads up on the potential winter peak. So that's great that we continue to update that.

So on slide number 22 I understand that you're comparing the 2022 versus 2040 hour 18. And I see the PV impacts would be positive. So that is because -- could you just kind of help me understand?

MR. FUGATE: Yes. I was wondering if anyone would notice that.

Yes, so that is coming from, as you noted, the July versus September peak. So in July at that hour 18, you actually have quite a bit more -- even though you have less capacity at the start of the forecast, you actually have more generation than you do on the peak day, hour 18, which falls in September towards the end of the forecast.

VICE CHAIR GUNDA: Got it.

Thank you.

I guess I think the last question on monthly peak loads, the distribution that you have for the 2022 versus 2023 results.

The green line, which is our new 2023 update, just specifically kind of -- you mentioned this in your voiceover, especially the difference in month one and month twelve, the reduction, could you give a little bit more flavor on why you think that's happening?

MR. FUGATE: Are you referring to the reduction in our overall peaks for this month, or for the sort of reduction in evening peaks?

VICE CHAIR GUNDA: The monthly peaks.

MR. FUGATE: Yes.

You know, we're always going to be tend to be a little bit low just in this process. Some of it comes from the calibration step as we, you know, sort of stretch and shift the profiles to align with the summer peaks, you know, to keep generation consistent across the whole year. The sort of lower load hours get shifted downward a bit.

That contributes to it to some extent but, you know, they're lower than all recent historical values. So that is also I think something that warrants a little further investigation.

VICE CHAIR GUNDA: Got it.

I think I have one process question, but I will just say, excellent presentation. And Nick, I heard you say it very loud and clear how much work its been. And thank you. Thank you for kind of lifting all that work. And for all those people that are putting all this work on your shoulders, you know, I apologize for them.

MR. FUGATE: That was specifically for you, Vice Chair.

VICE CHAIR GUNDA: Thank you.

Just on the piece of -- I think the last piece is, how well coordinated are we on -- you know, as we're making these changes on, you know, the implications of new climate data and all, I remember the question around -- I forget the word -- it's the correlation of the other data with the behind-the-meter PV, I'm just kind of forgetting -- like that we needed to make sure the distribution that we consider for behind-the-meter PV is consistent with the rest of the distribution, right? There is a weather correlation there? I know that was a kind of CPUC interest for a long time.

How are we doing on that front?

Like what I take away from your slides here early on in your HLM updates is -- maybe this is something I'll separately follow up with, but the new simulated ratios on your slide 13, you kind of discussed how the historical weather patterns are better correlated now.

MR. FUGATE: Right. Right.

VICE CHAIR GUNDA: So does that solve the ask from PUC?

MR. FUGATE: I mean, sort of indirectly in the sense that that is what facilitated this update to our base profiles, and caused us to, you know, to reevaluate those profiles and come up with system profiles that behave a little more in line with what recent history suggests.

So yes, to that extent, but there are other considerations. That's for estimating models and coming up with that base profile.

Then you move into the forecast period. You know, we had a little bit of discussion just in the earlier presentation about sort of also introducing variability in the PV performance and the forecast horizon. And I think that's of particular significance for -- you know, as we move into kind of developing inputs for stochastic modeling. But then also I think there is perhaps still some room to modify our treatment of PV in kind of the normal hourly forecast as well, to reflect a little more variability.

VICE CHAIR GUNDA: Great, thank you.

Heather, just want to plug for you. I need to step out. I'll be listening in, but I'll be muted for a little while, so if you could take over from here.

Thanks Heather.

MS. RAITT: Great.

Thank you, Commissioner.

Are there any other commissioner questions for Nick?

COMMISSIONER HOUCK: No, I don't have any, but I appreciate the presentation and the dialogue with the questions from Vice Chair Gunda.

COMMISSIONER SHIROMA: Okay. I have -- and forgive me, because you folks have done numerous workshops and so forth -- but the AAFS, I just, on that slide 22, and this is the 2040 outlook, is the AAFS, is this regulatory -- remind me, is this regulatory given in terms of what's required by 2040 for alternative fuel?

MR. FUGATE: I wonder if I could ask one of our electrification folks to chime in on that.

VICE CHAIR GUNDA: Commissioner Shiroma, I'm sure we have -- I'm just like looking to know -- we have Ingrid on the line.

Ingrid if you want to comment.

MS. NEUMANN: Yes. Yes. Yes.

I was just unmuting.

So there is - there are both programmatic influences and then zero-emission standards. And the zero-emission standards, which consists of the CARB state implementation plan, is really what takes over in 2040.

So that's most of what we're seeing there.

COMMISSIONER SHIROMA: Okay.

Thank you.

MS. JAVANBAKHT: And just to add to that, CARB's zero-emission appliance standard is still preliminary. They just kicked off that rulemaking earlier this year, but it will go into effect in 2030 if it's finalized.

COMMISSIONER SHIROMA: Okay.

Thank you. Very insightful. Thank you.

MS. RAITT: Thank you, commissioners.

So if we're ready, then we'll move on to -- let's see, we have a few questions from attendees.

So Heidi, if you could moderate that, that would be great.

Thank you.

MS. JAVANBAKHT: Yeah.

So we'll start with hopefully an easy one.

Nick, what is the expected date for docketing the preliminary results? And can you confirm, these are going to be posted as Excel files?

MR. FUGATE: That's a good question. I'll have to coordinate with Raquel on that, but I'm hoping to get them up this afternoon after this workshop.

MS. JAVANBAKHT: Okay thanks Nick.

MR. FUGATE: It'll be either -- I don't know if we can post -- I currently have them as CSV files. I don't know if we can docket those, but if not, then yeah I'll convert them to Excel files.

MS. JAVANBAKHT: Okay.

And then we've got a question on the transportation load profiles.

Quentin, could you hop on to help with answering this? And the question is from Charlie Allcock and the question is, how did the CEC staff develop hourly load profiles for charging loads for medium- and heavy-duty vehicles, especially the Class 8 truck drayage use cases that will electrify first?

MR. GEE: Hi. Quentin Gee from Energy Assessments Division.

Thank you, Charlie, for your question.

The way that the load shapes work overall is that we start with input load shapes that as of now are informed by what we call the AB2127 report. That's the report filed by our Fuels and Transportation Division that assesses electric vehicle charging infrastructure needs.

That report employed a tool, the results of a tool, called HEVI-LOAD that we work on with the Lawrence Berkeley National Laboratory. From there LBNL derived base input load shapes for us to work with that are informed by truck usage data and by driving patterns that were assessed. And from there we have input load shapes. Our load model does show a responsivity to time of use rates as well, and so we incorporate those initial load shapes that would have a particular shape for, say, port trucks, drayage trucks, and then adjust those assuming that -- with the underlying idea that some of the lead operators would alter their charging behavior to get the benefits of time of use rates.

The result is that approximately, I would say, you see a little bit of a reduction in demand during peak hours for drayage trucks, but it's not like it gets cut in half. It's only about maybe 25 or a little bit more percent reduction of its peak load. But we do assume that fleet operators will be somewhat responsive to prices, but not all.

MS. JAVANBAKHT: Thanks, Quentin.

That's all from the Q&A, but I did want to loop back. There were a couple questions on the hourly profiles for the fuel substitution pieces.

And Ingrid, if you could jump on and just say a little bit about how those hourly profiles are generated.

MS. NEUMANN: Sure.

We have normalized hourly profiles by end use, and then we have specific ones that we use for the fuel substitution for heat pump water heaters, and then for residential and commercial heat pump HVAC.

So for the residential portion of the heat pump HVAC, we have built profiles from building modeling and all the different -- 16 different building climate zones and have weighted those for residential. And we're working on doing that for commercial, but we haven't incorporated those kind of updated heat pump HVAC load profiles for commercial yet.

MS. JAVANBAKHT: Thanks, Ingrid.

Alright. Heather, I'm handing it back to you. That's it for the Q&A.

Heather, you're muted.

MS. RAITT: Thanks.

Oh my gosh. Okay.

Well, I said thank you Heidi, and Nick for your presentation, and Ingrid and Quentin for jumping in there and helping with the questions.

So we're going to move on to the public comment period, and so if anyone wanted to make a public comment, we'll limit it to three minutes per person.

Please go ahead and use the "raise hand" function on Zoom to let us know that you'd like to make comments. And if you're on the phone, you press star nine and that'll let us know that you want to make comments.

And I am not currently seeing any, but we'll give it a moment.

So again, just press "raise hand" on Zoom. And then if you're joining by phone, you press star nine.

Alright. Well I am not seeing any comments, so we'll just move on.

Just to wrap up again, we will be having the results. We'll get those posted today or if not today tomorrow, and moving towards adopting the forecast at that January 24th business meeting and, and then we'll be incorporating the results into the final IEPR and we'll be putting that out probably early January -- excuse me, early February, for adoption of the February business meeting with the Energy Commission. And written comments, if folks want to make written comments, they are welcome, and they are due on December 29th, and we welcome any input. And before we close out, Commissioner Shiroma or Commissioner Houck, would you like to make some final remarks?

Thank you for being here.

COMMISSIONER SHIROMA: Alright. Sure.

Thank you for the opportunity to listen to the very informative presentations and discussion. I thought the questions were good ones in the Q&A. I appreciate the answers given.

And again I appreciate the enormity of the work that is entailed in putting this together.

And thank you Heather, and to the entire IEPR team. And all best wishes for a wonderful holiday for everyone.

Thank you.

COMMISSIONER HOUCK: And I'll just echo Commissioner Shiroma's comments.

Just wanted to really thank you Heather, the staff at the CEC, Vice Chair Gunda, Commissioner Monahan, for all of the work on this. This is just really critical work that's just -- and the coordination between the two agencies is just really important to make sure we're getting things right.

And just appreciate being able to be part of the workshop today and wish everyone happy holidays.

And again, thank you.

MS. RAITT: Wonderful.

Well thank you both again so much. Really appreciate your time and being here today. And so thank you to everybody who joined remotely, and to our presenters.

And I think that is it for this workshop, and I hope everybody enjoys some nice holiday time. Take care.

(The workshop adjourned at 2:30 p.m.)

CERTIFICATE OF REPORTER

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of March, 2024.

Elise Hicks

ELISE HICKS, IAPRT CERT**2176

CERTIFICATE OF TRANSCRIBER

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified transcriber and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

I certify that the foregoing is a correct transcript, to the best of my ability, from the electronic sound recording of the proceedings in the above-entitled matter.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

March 7, 2022