COMMITTEE HEARING

BEFORE THE

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT

COMMISSION OF THE STATE OF CALIFORNIA

In the matter of,	)	
	)	Docket No. 14-BSTD-01
	)	
2016 Title 24, Part 6	)	
Building Energy Efficiency	)	
Standards	)	

STAFF WORKSHOP ON

UPDATE TO THE LIFE CYCLE COST METHODOLOGY AND

TIME DEPENDENT VALUATOIN FOR THE

2016 UPDATE TO THE BUILDING ENERGY EFFICIENCY STANDARDS

CALIFORNIA ENERGY COMMISSION

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INDEX

P R O C E E D I N G S

APRIL 29, 2014 10:03 A.M.

MR. LOYER: My name is Joe Loyer from the California Energy Commission, the Building Standards Office.

And my presentation basically is a background of the life cycle cost analysis and the TDV, how they basically came into being. So, why the Energy Commission uses the life cycle cost.

And we use acronyms here. Boy, don't we. So, LCC, life cycle cost analysis, TDV, time dependent value.

So, why the Energy Commission uses the LCC? The LCC, before there was a TDV, why and when we added in the TDV? And how the TDV is developed and then basic changes from 2005 to 2013.

And I think one of the things that we were going to include in this that we chose not to, was an actual example calculation, primarily because this is not the interesting part.

The interesting part is coming on later when we talk to Angela and when we talk to E3.

So, why do we do this? Why do we do a life cycle cost analysis?

We have been instructed to by the Warren Alquist

Act that’s in the statute, Public Resources Code 25402(b)(3).

And essentially here, it’s right up here on the screen so I won’t read it verbatim, but you can see I’ve bolded the cost effective and life cycle cost analysis.

We’re supposed to do a cost effective assessment of the building standards as they become -- as they move into being adopted by the Energy Commission.

That analysis has got to cover the economic life of the structure and has to show that the standards that we’re proposing are in fact cost effective over the life cycle of the structure.

So, what is a life cycle cost analysis? And I particularly like this little graphic. This is just a simple little thing I threw together, obviously, pretty quickly.

Basically, we’re comparing benefits to costs over the life of the building. And we’ve done that from the beginning and we intend to do that going forward. That is a requirement under Warren Alquist.

Now, how we end up defining costs and benefits, and the life of the building really is how things have changed over time.

So, before there was a time dependent value we still did life cycle cost analysis. And the main difference is the life cycle cost method was an annual -- annual values.

The change in the initial cost of construction minus the present value of the electricity cost savings, minus the present value of the natural gas cost savings.

You can also add into that the savings from propane, as well.

Essentially, it was very simple. There was a discount rate. I think it was three percent. It's three percent today. I think it was still three percent then.

The life cycle costs, they were set at 15 and 30 years, 30 years for residential measures and 15 for nonresidential measures. Also, some nonresidential measures were calculated at 30 years as well, even then.

So, the benefits, essentially we ended up with six multipliers. So, you had three for electricity, dollars per kilowatt hour, three for natural gas, dollars per therm. And if you were using propane at that point, also three for them.

And this was sufficient to show that the measures under consideration were cost effective and are cost effective.

So, I think the -- just a moment.

The main item here that we want to -- you know, that I wanted to get across is that we are looking at six factors that was it.

Now, when we moved to the TDV, to adding in the TDV, that was added in in the 2005 update.

Now, the significant difference is when we looked at the -- when we looked at the annual TDV, the annual TDV did not provide a way to value peak versus off-peak measures.

The 2005 update to the standards, the Energy Commission approved the first TDV. The TDV produces a monetary value for energy for each hour of the year. This gives us a way to account for seasonality, for time of use. It also enables us to use a time series present value instead of an annual average.

We’re also able to break the TDV out into 16 separate climate zones.

So, we went from six values to almost -- to more than 1.2 million values.

And just to go over the math real quick, that’s three building groups, residential 30 year, nonresidential 30 year, nonresidential 15 year; three energy sources, electricity, natural gas and propane; 16 climate zones. That’s 144 separate TDV series, each one of those series having 8,760 hours, 1.2 mil from six.

Now, how -- and, basically, as the TDV series developed, they're developed for each climate zone. They're developed for each building type in terms of 15 year and 30 year.

They use the natural gas forecast, they use transmission and distribution costs. They enfold in emission costs, ancillary service, peak capacity costs, and revenue neutral adjustments. These are basically fixed costs.

The natural gas series also uses our natural gas rate forecast. And the propose series generally depends on the Department of Energy's Propane Retail Forecast.

And I'm sure that E3 will correct any errors that I'm making here, so I have no fears about that.

And this, mercifully, for everyone involved, is my last slide.

These are the basic changes and these are very basic changes, from the 2005 standards TDV up to the 2013.

And the 2016, E3 will be -- we will be discussing. That's our main focus today.

The 2008, we can see we have the power exchange, day-ahead market prices, the consideration of avoided costs for customer outage, and the consideration of adverse impacts on customers when demand response is operated.

In this particular instance, I always thought the demand response was an interesting effect. Demand response, most of the time when we talk about energy efficiency measures we're talking about maintaining the same comfort levels, maintaining the same lighting levels, but doing it more efficiently.

This particular demand response was, essentially, we're going to make people more uncomfortable because we have to. The power's not available, by whatever means, we have to turn down the lights, we have to turn down the air conditioning, that's what this meant. And that was folded into the TDV.

The 2013 update correlating weather and load, the mid-term price market prices shapes. Basically, we're enfolding in the renewables, RPS predictions.

We used a higher retail rate forecast and we used the statewide retail rate adjustment.

And I think the most interesting part of this is when we -- to me, anyway, and that's not to everybody, but that was when we correlated weather and load better.

The problem there, prior to this, is that the maximum load was not happening at the peak hour of the hottest day and that is problematic. It wasn't happening in the middle of the night, but it was happening off-peak. And that made it very problematic to use the weather data in the same context as the TDV.

And so, for the most part that was corrected. I think there's still some work that needs to go on that, but that's not bad.

So, from there I think we're going to go ahead and move quickly onto Angela's presentation.

And Angela, if you are ready?

MS. TANGHETTI: I am.

MR. LOYER: Very good. I'll go ahead and load yours up here. There we go.

MS. TANGHETTI: Okay and then I just hit page down to --

MR. LOYER: Or just click the button.

MS. TANGHETTI: Okay, I'll have more acronyms for here, as well.

Good morning, I'm Angela Tanghetti and I work with the Electricity Analysis Office. And I'm going to provide some details on our contribution from our division, which is the Electricity Analysis Supply Division, to this Energy Efficiency Division's Title 24 TDV update.

I've worked with production cost models at the Energy Commission for many years, more than I need to mention here. But this is my first time participating in this TDV process.

So, I just want to say it's been a real pleasure to work with the Efficiency Division staff. You know, we all work in the same building, but we don't always interact and understand what each other is doing, so it's been a nice opportunity to work with them.

It's also been a good opportunity to work with the staff at E3, Eric and Brian, as well. So, after all these years, we can still learn something new here.

Today, let's see, I'm going to go over -- this presentation's mainly going to focus on the production cost model key drivers and some of our selected simulation results.

And in production cost modeling there's many, many, many assumptions. But this morning I'm only sharing those that our team thought most relevant and influential in this analysis.

And again, since I'm new to this process I'm not sure, you know, of the audience. And if there's something that you think is relevant or interesting, that we may not be presenting today in this slide deck, definitely please ask.

Not that I can keep all those details in my mind, but since we've just completed the IEPR analysis some of them still are fresh. If they're stale ones, I'll need to follow up on it after the workshop with you on that.

And when I present the simulation results they're aggregated, obviously, since we ran hourly simulations for eight years, for three scenarios, for the entire WECC. So, we could bury you in data, but what we've tried to do is aggregate them in some way.

Hopefully, it's relevant. If not, please ask and we can provide more details on that, as well.

Let's see, some of the TDV scenarios -- oh, the TDV scenarios. In the 2013 IEPR staff from all divisions that developed some type of forecast with models spent many, many hours coming up with what we're calling our three common scenarios.

And again, our mid-scenario is pretty straight forward, but the low consumption and the high consumption scenarios that we developed caused a bit of angst amongst our multi-disciplined group, staff there.

So again, the low consumption scenario that we're using had the lowest peak in energy forecast. And that was driven mainly by econ and demo assumptions.

But this low consumption scenario also had the highest fuel and energy price assumptions imbedded in that, as well.

A third scenario that we're presenting here was not part of the IEPR 2013 common cases, but one our team thought relevant. And that is the 40 percent RPS by 2024 scenario.

Again, with this 40 percent by 2024 scenario, all the other assumptions are the same as the mid-case.

And we thought this scenario should be considered since higher amounts of renewables -- of certain types of renewables may influence when we observe the peak for electricity demand in future years.

And also, this 40 percent RPS scenario, or 40 percent by 2024 RPS scenario, it’s also been vetted in the CPUC’s 2014 LTPP process, and is also being studied in the Cal-ISO’s 2014-2015 TPPP process, if you’re familiar with those.

Let’s see, oh, some of the key drivers affecting simulation results that I’ll go over today. Again, I’m only sharing a handful of assumptions that are needed for production cost modeling but, again, we thought that these are the key drivers.

Naturally, one of the Energy Commission’s most highly regarded forecast is the energy demand forecast. And this was recently completed in support of the 2013 IEPR, so we’re starting with a very fresh set of demand forecasts here.

A companion to this adopted demand forecast is the IOU forecast of additional achievable energy efficiency, AAEE, and also the incremental energy efficiency that is for the POUs.

So, the AAEE forecast is only for the IOUs, whereas the incremental EE came from the utility S filings.

And when I say it's a companion, the AAEE forecast is a companion to the forecast is that every effort was made to ensure that the additional energy efficiency was not already counted as part of the demand forecast.

Also what I'll be sharing with you today is -- with the completion of the California Greenhouse Cap and Trade market options, Energy Commission staff, with input from stakeholders, was able to develop a range of possible future GHG prices, so I'll share those with you, as well.

Other key drivers, also in 2013 Energy Commission staff developed a methodology to develop burner-tip natural gas price forecasts.

And these forecasts are based on the wholesale regional prices for gas, for natural gas, and those are developed by the Commission's NAMGas model.

So, the burner-tip methodology takes those wholesale prices a step further and includes transportation, as well as some other components necessary to calculate the burner-tip gas price forecast.

And again, that’s available for all regions for the WECC on a very granular topology. So, California has about ten regional burner-tip gas price forecasts.

We’re also going to share the Energy Commission staff incremental RPS portfolios for each of the three scenarios that we ran for this TDV analysis.

And when I say incremental, I mean incremental over those that are currently operational. So, we feel we’ve done a very robust assessment of what came online through December 31st of 2013. So, these are just incremental in order to get to the 33 percent or the 40 percent by 2024 RPS case.

And another driver in these production cost model simulations is the hydro generation forecast. And the reason I bring these up is because these TDV analyses, we don’t start running the simulations until 2017.

So, we didn’t include any assumptions regarding current drought type scenarios. We thought by 2017 that the WECC in California would begin to return to the average.

So, again, we’ve just used an average forecast for hydro generation throughout the WECC. And again, that forecast is based on 1992 to 2012 actual operations.

Okay, the demand forecast, again that we're using here, we're using a low demand scenario. And the low demand scenario did assume higher energy forecasts.

You'll see in the next slide how that translates into the incremental EE. But again, the forecast -- they developed a forecast for 2014 to 2024.

I'm just presenting a single year here for forecast. But if you need the additional years, those are already posted on our website and adopted.

So, again, I like the way the demand forecast describes the mid-scenario and it's best described as in between the high and the low, so these are what we present here.

Again, these are the adopted AAEE scenario, or incremental energy efficiency. They actually developed five trajectories of energy efficiency in the future. And the way they're combined is with the low demand scenario we observed the highest amounts of additional energy efficiency.

And the thought on that is with higher electricity prices users are going to be more incentivized to adopt higher amounts of energy efficiency with higher electricity rates, higher fuel prices.

So, again, these are the scenarios for 2024. They're available for 2014 through 2024. Again, those are posted to the website, but I just thought I'd give you a little flavor of what it looked like for 2024.

The Energy Commission, the production cost model dataset, we need to use publicly available data. And at this point there wasn't a source for publicly available GHG price projections.

So, myself and Karen Griffin, a senior staff member in my division, we consulted with staff at the PUC, the Air Resources Board, *World Trade Press*, and we developed a method to come up with a mid-range projection of future GHG prices.

The method we used to develop the starting point for this mid-case scenario was based on the five auctions that were already held in 2013, so it's basically a weighted cost from those five auctions.

Again, and then this burner -- not this burner -- this GHG price, the beginning price in future years was grown at CPI plus five percent, and that's described directly in the ARB Cap and Trade regulations.

Now, for the high and the low forecast, we also had to develop those for the common case assumptions for the 2013 IEPR.

And the mid and the low forecast assumptions, they assume sufficient amounts of what we’re calling the AB 32 Complementary Programs available to reduce emissions during the first two compliance periods.

And when I say first two compliance periods, that’s through the year 2020.

After that we’re assuming that the mid-case GHG prices will grow at about 1.5 times the low price scenario.

So, again, the mid and the low are the same up through 2020 and then they take a different trajectory after that.

The high price GHG scenario was always three times -- we’re assuming it’s always going to be about three times the low price scenario.

So, again, I’ve just selected a couple years here to share. We did develop a forecast for 2014 through 2024 for the GHG prices that are also available and they’re an addendum to our Natural Gas Outlook Report.

And the reason we came up with the high and the low ranges is we’ve looked at this report documented here, and this report was authored by the Emissions Market Assessment Committee and the Market Simulation

Group that advise CARB. And again, they looked at this and their study came up with the assumptions that there are sufficient complementary programs to keep the price at the low level through about the year 2020.

Let’s see, the burner-tip gas price forecast. Again, what I’m showing you here is simply a California weighted average. What we do is we have many different pricing zones in California based on transportation rates, where the power plant is, some type of taxes.

So, again, we develop a very granular burner-tip gas price forecast.

But what we’ve done here is taken the regional prices and weighted them with the amount of natural gas from our simulations.

So, again, these are just the weighted price of natural gas in those two years for California as a whole.

Others have contended that our forecast is too low, too high, and specifically with regards to the annual energy outlook developed at the Federal level for California.

And we’ve seen those prices. However, there isn’t any documentation, yet, on their assumptions that are driving those. And staff just doesn’t feel in a position, yet, until we see the assumptions that are driving the AEO forecast in order to compare it to ours.

Our assumptions are posted with our natural gas outlook, so those are readily available.

And as soon as those are posted by the Annual Energy Outlook staff that will then be in a better position to compare our forecast to somebody else's.

Okay, also what we thought would be interesting was the incremental renewable portfolios.

And the first two, again the first two columns are the common cases using the analysis in support of the 2013 IEPR for the mid consumption and the low consumption scenarios.

And the last, the third column here shows the incremental RPS portfolio developed in support of the TDV for the 40 percent RPS by 2024 scenario.

And again, this last scenario is fundamentally consistent with the scenario, the 2024 40 percent RPS scenario that has been vetted and developed in support, again, of the LTPP process at the PUC, and also at the TPP process at the ISO. So, they're studying that 40 percent by 2024 scenario, as well, in roughly the same increments of new renewable additions.

Again, this is incremental to what is already operational as of 2012, 31, 2013.

Okay, I just wanted to note here that PLEXOS does not include costs for ancillary services or in our production cost model dataset, nor is there any fixed ONM (phonetic) component. Strictly cost-based simulation results are provided for this TDV analysis from the Commission’s PLEXOS production cost model.

So, I just wanted to make that clear that these are not market clearing prices or wholesale price of electricity. They’re strictly the cost of production, which is how generally the model’s being run in many forums, currently.

A busy slide, I know. But, you know, again, what I said with hourly data for eight years, for the entire WECC it’s not always possible to be neat and tidy.

But I just want to show here that we’re presenting differences from the mid-scenario. So, I’m not presenting any single scenario, I’m just presenting the differences in a couple years’ of simulation results.

So, again, it’s the difference for the low consumption/high price scenario from the mid and the 40 percent RPS by 2024 difference from the mid. So, again, these are differences for 2017 and 2024.

And even though these are highly aggregated, we thought these were somewhat interesting in that some of them were a bit counter intuitive to what we expected. Whenever you run a simulation you always think, you know, how it should turn out and when you start looking at your simulation results and you see things that are somewhat counter intuitive, then it causes you to pause and look at those.

And so, we had assumed that in all regions, that the 40 percent RPS scenario should produce negative marginal costs when compared to the mid-scenario.

But as you can see, the San Diego and to a lesser extent the PG&E Bay transmission areas didn’t come out exactly as expected.

And this is in part due to the fact that San Diego and PG&E are not exactly rich in renewable acreage, per se.

When we came up with the 40 percent by 2024 RPS scenario it was largely small solar, solar driven which requires large amounts of acreage.

So again, the PG&E valley and SCE were very rich in additional renewables in those two portfolios.

So again, a little bit busy slide, but we just wanted to show some results that we thought were a little bit counter intuitive and provide an explanation why.

And so, what I’m showing here is basically another busy slide. And again, they're differences. And the low consumption scenario, the low consumption scenario's not quite as interesting. They're only for a selected region. This is the PG&E Bay.

The low consumption scenario will always have less generation than the mid just because they're using different demand forecasts.

But this is just showing some of the impacts of adding additional renewables to the portfolio and how it could impact generation in that local area.

And it's also impacted by the amounts of energy that it can import to those regions.

So, the SCE region was very clear in that the prices were definitely negative. And you can see that it's mainly driven by the amounts that there's more renewable generation on the margin in the 40 percent RPS scenarios, which tends to lead to lower marginal costs because there's basically no fuel costs.

There are other components for those resources, some variable ONM, but in the most part it's driving the costs down because there's no fuel costs associated with those.

And as you can see in the San Diego area again it's not really renewable rich, so what we're seeing is the positive impact on the marginal prices in those areas, either from it having to start up additional generation or possibly import more generation that was a little bit higher cost than in the mid-case.

So, again, a lot of simulation results, a lot of input assumptions. But I just tried to pull out a few that the team thought was interesting to present to this group and how they could potentially impact the TDV analysis.

So with that, if you have any questions, if you want to follow up afterwards, my contact information's at the beginning of the slide.

So, thank you.

MR. LOYER: Okay, I believe this one is yours, all right.

MR. CUTTER: Okay, thanks for coming today. I'm Eric Cutter, a senior consultant at E3. And I'm joined here with Brian Horii, a partner at E3, and we'll be going through our preliminary results of the TDV.

So, we've taken the inputs, many of them from the IEPR that Angela just went through, and run them through the avoided cost model to come up with the $87.60 hourly TDV factors -- or prices.

And so I'm going to start out with what the main updates we're undertaking for this round are and then Brian's going to walk us through some of the results in the TDV model.

And so, we’ve put the -- there’s a number of updates to the avoided cost methodology that E3 has developed that has been used both at the CPUC for energy efficiency and demand response, and as a methodology for the TVD calculations here for the building standards.

You know, the main drivers of those inputs are listed up here and these are the updates from the last go around.

As you would expect, more recent gas forecasts, the new marginal costs from the IEPR, PLEXOS production simulation runs, and the greenhouse gas cost forecast.

So, those all come through -- both are inputs into the PLEXOS runs that produce the marginal prices, energy, kilowatt hour prices that go into the TDV, and are also inputs themselves into the TDV calculator in terms of how -- in some cases, how the values get allocated to individual hours over the year.

The next two major updates and we’re going to go into these into some detail, the main one is the transitioning from the net qualifying capacity method of allocating capacity value to an effective load carrying capacity.

And for now, in short, this is essentially trying to measure the increment, the marginal value of a resource, how it changes over time with the changing portfolio.

And so we'll see, as compared to prior methods, this ends up producing a capacity value both that is lower over time as we get higher penetrations of solar, and later in the day.

And that has some implications for the shapes of the TDV values and how the measures compare to each other.

And then, we've also updated the marginal costs from the most recent rate cases from the electric utilities.

So, there's always this tension on the building standards is at the end of the day we need to have one set of numbers that the building models and the developers can use.

But we know things are going to change quite a bit over the life of the building, over the next 30 years in ways we can somewhat imagine and ways we can't imagine.

So, in this round we want to take a look specifically at how some of those changes might affect the TDV output.

And at this stage is purely an investigative exercise to see what -- for example, how the higher greenhouse gas forecasts would change the level and the shape, potentially, of the TDV numbers.

So, we're going to -- we'll show some of the sensitivities that we've run through with the help from Angela's group.

For all the detail of the updates since the last round of the TDV calculator, the most recent report is listed here. It's the net energy metering cost effectiveness analysis, or ratepayer impact evaluation for the CPUC.

And in the appendix to that report is a long list of all the major and minor updates to the methods and the calculators that have occurred over the last three years.

And they've been quite numerous from different proceedings, energy efficiency, demand response, SGIP, distributed generation. Each time there's a proceeding, there's usually some methodology updates that go along with that, and all of those have been incorporated in the calculator that we're using for the TDV for this round.

So, we're going to start off with the easy ones because we don't need to get into the $87.60 hourly.

So, the natural gas and propane, as Angela mentioned, this is a graph showing -- the red line on the bottom is the CEC forecast from the IEPR that is being used in our calculations for the TDV and how it compares to the gas forecast that we used in the last round of updates and to the EIA.

And as Angela mentioned, both of those are quite a bit higher.

I wanted to point out on this slide we’re not -- for the purposes of comparing these in the TDV, you’ll notice that the X axis is in year one, year three, et cetera.

So, in 2011, we’re starting with 2013 is the first year and in this round we’re starting with 2017 as the first year.

But because we’re evaluating the impacts over the life of the building, it proved to be a more apples-to-apples comparison showing the gas forecast on this method, as we take a snapshot what it would have looked like in the last 2013 update and what it looks like in this 2017 update.

So, these results lead -- those gas price forecasts lead to these results here for the TDV factors. And again, even though the -- we know the gas price forecast has both gone up and come down since the last round.

The two dotted lines show the residential and nonresidential in the top, in the dollars per MMBtu. And we can see that in this round the blue, the res, both start out lower and end up slightly higher.

That all translates to the punchline in the bottom, which shows the solid lines are 30-year res, 15-year nonres, and 30-year nonres TDV.

And by and large they're all lower than the factors from the last TDV, round of TDVs.

Any questions so far? This is the gas. And let's see, if we have -- the propane looks similar. The one change for the propane is converting the natural gas forecast to a propane price, which is based on the EIA Annual Energy Outlook.

So, essentially the same shapes as the natural gas. Also, in this case, the propane is consistently lower than what was used in the last round of updates.

So, I went through that pretty quickly. We're going to get into the TDV for electricity and we're going to jump into the results, and then Brian will go through some of the calculations.

We're going to be showing throughout the presentation average annual shapes, but we wanted to highlight that that annual average really masks a very peaky shape to the TDVs.

And those spikes are where the transmission and distribution capacity have been allocated and the system capacity have been allocated.

So, even though the averages look nice and smooth, we are going to see a lot of spikes in the hourly numbers.

And so here the blue lines, the smooth blue lines are the shape of the TDV factors from before. And the red show the shapes currently.

And you can see, broadly, the main impacts are two. They're peakier, so we have higher peaks in the midday and in the evening, early evening, and somewhat lower throughout the rest of the day.

And this has in part to do with the change in the allocation of the capacity value. And it has in part to do with using the ELCC methodology.

And I'm going to leave it to later to explain the double humps in those because there's a few factors that go into that, that Brian will explain.

But it has to do with the weather falls and the solar load shapes.

And so, we see similar for -- so, see, that before was the 30-year, the nonres 15-year. It's similar, lower throughout the year, higher on -- sorry, lower throughout the day, higher on the peak.

I think we've listed all of these here. The other major input that maybe we haven't gone into a lot of detail is the rate forecast from the IEPR is one of the major drivers for the TDVs, in that all the wholesale electricity costs are then increased by retail rate hour.

So, we get -- as Angela was describing, the production simulation gives us the marginal cost of energy, but is not accounting for any of the fixed costs.

So, looking at the impact on rates requires increasing that up to fully recover the revenue requirement that's associated with the plants, with the power purchase agreements, with all the fixed cost investments.

So, that rate forecast is also one of the main drivers of the TDV values.

And as I mentioned, the TND capacity values are a bit higher now than before and they're from the latest rate cases.

So, I'm going to turn it over to Brian, now, to go through some examples, in a little bit more detail, of the TDV calculations and results.

MR. HORII: Okay, thanks Eric.

So, a lot of what we've been talking about today have been sort of simple updates, basically, to the inputs that have been used in the past for TDV. You know, updates to the rates, updates to the gas cost, updates to the energy price shape from PLEXOS, et cetera.

The one area where we’ve actually made a significant methodology change is the way we allocate generation capacity cost to hours.

And we’re doing that now using this thing called ELCC that Eric mentioned earlier. So, that’s the effective load carrying capability.

And the ELCC, in a way, is very similar to what utilities have traditionally done with things like loss of load probabilities that many of you are probably familiar with and have heard about.

What we’re doing here, though, is we’re using a model that’s not one of the standard electric utility loss of load probability models, for a couple reasons.

One is those models were always -- or are proprietary models. So, when we would be in something, you know, a public proceeding like this or before the PUC, it was always difficult, if not impossible, to get that information from the utilities of what they thought, you know, their need was for generation and when they needed that generation.

So, we developed this ELCC model to be able to provide a public tool that could do those calculations, as well as focus in on the uncertainty associated with renewables.

Traditionally, those kind of models looked at variations in load levels, you know, uncertainty in load, as well as uncertainty in units, fossil units, supply units.

But that uncertainty was almost always focused on things like maintenance schedules, forced outages. It really wasn't considering things like the uncertainty over the availability of wind generation or, you know, solar generation.

So, that's what this model, this ELCC model really takes into account. It really looks at that uncertainty over renewable generation.

And, let's see, you'll see why that's really important in this next slide. And these are some slides we developed associated with this net energy metering work that we did for the CPUC.

And what it's showing is basically a movement of the peak from -- if you look at the stat sort of area chart, the little X on top, that's sort of where the peak occurs in like our current system, or our old system when you didn't have a lot of solar on the system.

But let’s say we moved on, so we had, you know, the addition of solar and maybe some energy efficiency. Maybe we’re now down to that next dash line.

And you’ll see now our peak has actually moved. So, we’re no longer looking at a peak of around maybe, you know, 2:00 or 3:00 p.m., you know, now maybe it’s 4:00 p.m.

And as you do more solar, you’ll see the dash lines, which represent your next net load on your California system. That drops down, but it also shifts the peaks later.

So, as you get more solar on the system, you get more of that shifting of your peak period later.

And that was a real concern that we had when looking at these building energy standards. You know, how would increased levels of renewable penetration affect the timing of when the California peak is and, therefore, affect the value that we want to give to different kinds of measures?

You know, would this mean that there’s more value for something like light, or maybe you see lighting in the -- or like residential lighting we see early evening.

And maybe it’s a decrease in the value of like commercial HVAC because those units are now, you know, shutting down and you're not seeing those cooling loads on your system when you're seeing your new peaks.

This next slide just shows how dramatic an effect, sort of recognizing the shift in the peak timing could have.

In this case it's looking at PV. So, it's looking at photovoltaics. So, obviously, as that peak shifts later in the day, the solar is starting to, you know, fade off and it's not able to really provide you much peak capacity.

And that's what you'll see in that bottom right chart there.

The top right is a representation of installed PV capacity on the system.

The bottom one shows the amount of sort of load reduction you're getting out of each megawatt of PV that you're putting in.

So example, you know, you'll start out getting 70 percent of the PV's nameplate capacity you actually see as a real peak reduction.

But you move, you know, maybe to the point where you've got 10,000 megawatts of PV installed. Now, each new megawatt's only giving you, maybe, 30 percent or 35 percent. And so, it's that degradation in value as your peak shifts.

That’s what it is we’re looking at for these building standards, would we see similar sort of degradation or shifting in values for different measures.

Okay. And so, again, in appreciation of that let’s look at, well, what do these capacity allocation factors really look like?

So, the top graph on the right here is the 2013 ELCC capacity allocation factor. And so this is just showing how we’re going to spread the value of generation capacity two hours of the day. And we’re showing it for three months.

The blue line is July, the red is August and the green is September. And you’ll see they all pretty much have the same shape. They’re all sort of peaking around, you know, 3:00 p.m. standard time, or 4:00 p.m. daylight savings time.

But then if we look, now, at the bottom chart, this is looking at, well, what would this look like in 2020 when we have the expected amount of wind and solar now installed?

Now, you’ll see that for July and August they still tend to be peaking around the same time. A little more spread out, but still sort of around that 3:00 p.m. to 4:00 p.m. standard time.

And September you see a little bit of that, as well, but also you'll see there's new peak for September that's popping up around the hour ending 6:00 p.m., 7:00 p.m. standard time.

So, that sort of introduced this new later peak and this new value, basically, that the building standards would give to measures that are sort of either saving energy or sort of penalizing measures that are using a lot of energy at that time, where you wouldn't have seen that in the current system.

Now, whenever we show these we always get questions because we get this sort of double hump effect that Eric was mentioning earlier.

You have that peak around, you know, 3:00 to 4:00 p.m., the kind of traditional peak. But then you get this second peak in September and when you add all that up -- let's see -- well, when you add all that up you'll get this kind of double peak.

And so, we wanted to sort of look into that a bit and figure out, well, what's really driving that?

And one of the first things that always surprises people is just this September peak. The fact that now we -- because everyone thinks about peaks more in July and August.

And the reason we're seeing the September peak is because of the weather files we're now using, these new -- you know, what are they called, CT 2010 weather files.

And so what we've done in this slide is pulled some of the weather from, you know, six climate zones. And we wanted to show that if you look at September for Oakland, for example, you'll see that that is pretty close to the overall annual peak.

Los Angeles that actually is the annual peak is occurring in September, in the files.

Now, in an area like Fresno, you know, the peak really is still occurring in July, but September is very high. September really isn't that far below average in terms of the temperatures.

Riverside, surprisingly, it's peaking in September as well.

Sunnyvale the same thing, it's peaking in September. And Sunnyvale is very odd because Sunnyvale you actually see kind of this big drop in mid-July and August, where you don't have the temperature peaks in the weather file there.

And in San Diego, of all places, even it's peaking in September.

So, I think it's this early September peak we're now seeing in all the weather files that are now assigning all of this value, capacity value to September that we never saw before.

The other thing I wanted to point out is that when we looked at, well, what the maximum temperatures were in like September versus July, we're plotting here the September temperatures in red, the July temperatures in blue, and just the difference between the two in green.

And what we noticed is that in a lot of these climate zones, the September temperatures it just tended to stay hotter, sort of longer into the early evening, late afternoon, early evening.

And so I think the combination of that, along with the fact that solar output is declining, and we know as we move, you know, later into September the sun's going down earlier and earlier in the year. So, you have these sort of sustained temperatures combined with solar output dropping that's causing this increased need for capacity sort of in September, in the late afternoon to early evening.

Now, to just show what the current capacity allocation factors are compared to the ELCC, we show the current allocation factors in the upper right-hand of this chart.

And I should mention that the current allocation factors, what they are doing is simply allocating to the top 250 load hours, system load hours that we previously had.

So, one of the big weaknesses there was there was no way to reflect what the allocation should be in a new world where we have a lot of renewable penetration. Basically, it was only sort of looking at the old world.

And so you'll see, you know, it's peaking, what, around 5:00 p.m., 4:00 p.m., 5:00 p.m. Pacific Standard Time.

If you compare that to the bottom chart, it basically overlays the two, so it's summing up all of the current capacity allocation factors in blue and comparing it to the new ELCC method in red. And you get this sort of this double hump in the red.

The double hump isn't so much the important point, I think, as we've sort of narrowed the capacity allocation. So, it's a bigger allocation to sort of a tighter window. We're not giving as much weight to these shoulder hours. These hours like, you know, hour ending 12:00 or 1:00 p.m. that we were in the previous method.

But, you know, despite all of the changes and the reasons why we're doing the changes, when you look at these results they're not really that dramatically different.

I mean, sure, when you look at this chart, you know, okay, it’s a little spikier but it hasn’t done a massive shift. It isn’t, you know, hugely different.

And I think that’s one of the reasons why when we see some results, later, you’ll see that the results haven’t really changed that much.

But before we get to that, I just wanted to give people an appreciation for the relative magnitude of these things.

So, what we’re showing here on this slide is for our mid-case we’re showing a decomposition of the TDV factors. Well, actually, not quite the TDV factors, the dollar-per-megawatt hour numbers that will later convert into the TDV factors. But we’re showing the decomposition.

So, what’s interesting is this first block, this light blue block on the bottom that’s our rate adjustment piece.

And I wanted to remind people that although we’ve been doing a lot of focusing on, you know, marginal costs, on capacity values, et cetera, at the end of the day we’re going to true all of those costs up so that the total average matches the retail rate forecast.

And that truing up is what you see in that large light blue box there at the bottom.

So, it’s sort of like the marginal costs are important for giving you shape, but it’s your retail rate forecast that’s really giving you your level. And it’s that sort of combination of the two that ultimately gives you your final TDVs.

So, compared to the rate adjustment, you know, the energy -- Angela’s group worked really hard on those. It’s maybe, I don’t know, 40 percent or 50 percent of the value of the rate adjustment in there, although it does give us the shape. So, it does give us that value.

Losses, that’s that little -- it’s a sliver or red. You can barely see it on there.

The next big flat piece is emissions cost. And then we have our -- well, ancillary services, you can’t even see it, it’s just too small to show up on the graph, but it is in there.

Angela mentioned before that ancillary services aren’t included in the simulations that they’re providing, but we do add that on so we don’t neglect that.

The TND piece is the next piece there and then that’s topped off by our capacity piece in purple there.

Okay, so the next slide is just showing -- although you couldn’t tell it from the prior slide because there’s so much averaging going on, you know, there is actually a good amount of variation in the annual energy cost. Well, I shouldn’t say annual energy cost. In the hourly energy cost, so that’s just demonstrated in this chart.

And so you’ll see, you know, if the energy costs are peaking, what, around 6:00 p.m., hour ending 6:00 p.m. Pacific Standard Time in July and August, which is what you would expect.

The next thing we wanted to do is show the generation capacity component and here we, again, see that kind of double peak.

We kind of have an earlier July/August peak and then that later kind of September peak.

The next thing is our T&D, which is kind of this -- more of this single hump mountain that we have. In this case we’re looking at climate zone 12, because I will point out that the T&D allocations will vary by climate zone because of the individual, you know, weather in each climate zone. But generally, they all have this kind of shape.

Okay, so that sort of walks us through sort of the major changes we’ve done, the reasons we’re seeing the kinds of shapes that we're seeing. And that would be sort of the traditional standard update.

But there are a few more things that we wanted to discuss with the group and get feedback from people.

So, one of the things that we're considering or we're looking at are scenarios. So, everything I've shown up to this point has just been for the mid-case.

But we also ran three other scenarios. So, we ran a low demand case, which is using Angela's low demand, so energy prices. And, you know, Angela went through a lot of the differences there so we probably, really don't need to touch on that.

Although, I think the most important thing is we do have a higher electric and gas rate forecast associated with this low demand case.

Remember, I was talking about that rate adder, that rate adjustment being important. Because we have a higher rate forecast for the low demand case, we'll have higher TDVs for that case, and you'll see that later.

We have a 40 percent RPS case. It also has a slightly higher electric rate forecast of 3.2 percent higher than the mid-case in 2020.

Slightly different natural gas forecast for electric generators, but very close. I mean, it's hardly different at all.

And, of course, we have the separate PLEXOS run from Angela for that.

We also ran a high GHG case. And in this case we actually didn't need a separate sort of PLEXOS run, but we assumed, basically, just an additional adder for the value of GHG emissions.

We used basically the same inputs as we've used in the mid-case, just increased our GHG cost. And so that was a simple scenario to run.

So, we look here at our natural gas rate scenarios. You'll see, let's see, our current or our 2011 gas, or the current gas in the current standards is the dashed blue line there.

And that's compared to our mid forecast, which is a solid blue line.

And then our low demand or high price forecast is the highest one there in green.

And we also looked at a high demand/low price forecast, which will just be there in purple.

For nonres we're showing the same information just there on the bottom right. So, here we've got the current ones in the dashed red line. The mid-case is the solid red line, and our low demand/high price case is the solid green line.

And I guess what's notable here is just the difference between the res and the nonres. Res gas, the mid-case is, you know, pretty close to what the current is and our low demand/high price case, you know, pushes that above.

In nonres we start out so much lower with our mid-case that even going to the low demand/high price scenario, you know, barely gets us up to the current gas levels and, actually, is still a little bit lower than the current gas levels.

The next slide is just looking at our electric rate forecasts, a lot of lines on this chart.

Our mid-case are solid blue and red lines, and the blue is for res, the red is for nonres.

And then you'll see just above those, and those are sort of the lowest pair of lines. Just above those are the dashed lines, which are the 40 percent RPS. Because, remember, we have a slight rate increase after 2020 for that case.

And then above those we have the two highest ones which are our low demand/high price scenarios.

The other thing I wanted to show is just our GHG cost forecast. Our base case is there in red and our high carbon case is there in green.

And although the high carbon looks to go really high, just remember it's just basically three times what the base case carbon forecast is.

But when you start to get out, you know, 30 years when you're doing compound annual growth rates, it tends to start looking pretty high.

Okay, so then we have -- well, if we look at all those rate scenarios that we were talking about earlier, well, what does that do to our actual TDVs?

So, here we look at the natural gas scenarios, looking at the TDV factors. The dashed lines in all the cases are the current, the solid blue are our mid-case, the red is our low demand/high rate case.

And you'll see those are all clustered pretty tightly. The green is our low rate case and so, as you expect, that's just a little bit lower than our mid-case.

The one that really kind of jumps out, though, is just this high GHG case; if we sort of assign an additional cost for that higher GHG, that really pushes up those TDV values substantially above the other scenarios.

Now, if we go to residential electricity, now, you'll see our black dashed line is our current standards.

The red solid line is the average of our mid-case, so that's pretty much the same sort of information that Eric showed you earlier.

Just above our mid-case you'll see that purple line. So, again, that's our 40 percent RPS case. It's very close to our mid-case, with just that little bit of a rate increase and that's why it's just barely above our red line.

When we go to our low demand/high price case, that's the green line, we get a little bit more of a bump because there's a more substantial rate increase under that scenario.

And then, when we look at our high GHG case that's going to be the highest one, just like we saw in the gas case.

But shape wise, they're all very similar. It's really driven mostly just by those rate forecasts for the low demand and the 40 percent RPS case, and then you get this kicker for your GHG of pushing that case up higher.

So, that was res. Nonres we see the same sort of relationship for the 15-year case and for the 30-year case.

I guess one thing I will point out that may be hard to see is just the GHG cost bump, it tends to be bigger in the sort of off-peak hours than in the on-peak period because there's sort of a constraint on how dirty the units would be in the on-peak period, so it tends to flatten that out just a smidge. But it's, to a larger sense, pretty close to a uniform adder.

Okay, so we've been showing you all these TDV factors, showing you all these profiles and I'm sure you're wondering, well, what does this really mean for a specific measure? You know, how different are these new TDV factors when I'm looking at what does it do to, you know, CFL lighting, refrigeration, HVAC, et cetera?

So, that's what we're showing here on this chart. So, here the dark blue is a CFL measure, the red is refrigeration, and the lighter blue is HVAC. And this is looking at a res 30-year case.

The far left is the current standards. The mid-case is just the right of it and you'll see, you know, it's very close. HVAC goes up the most which we'd expect because, remember, we saw under our new TDV factors that they're a bit peakier, or they're a bit narrower and a bit higher in the on-peak period so we'd expect to see that.

The high efficiency -- I'm sorry, that should be labeled the low demand case, or that's the one that had the higher rates, so you see everything kind of bump up compared to the mid-case or the current.

And you see the HVAC go up even further than the others.

40 percent RPS, it’s pretty close to just the mid-case, as we’d expect.

And the high GHG is the highest one of all.

But we really don’t see any of the relationships between lighting, refrigeration, HVAC, the relative relation of shift very much, other than HVAC getting this extra bump under the new factors.

Now, if we look at res 30 -- oh, and I should also mention that these are looking at climate zone 12, so it is a climate zone with the kind of weather you expect to see HVAC get a bump like that.

This, we’re just looking at it in a slightly different way, sort of comparing across scenarios for each of a different sort of end use, space cooling, lighting, fan cooling, fan heating.

What this really highlights most of all is that -- so the mid-case versus the 40-percent case, so the red versus the purple for any of these groups, you know, are very similar.

The low demand is going to be the next sort of bump up, the green, and then of course our high GHG is going to be the highest for any of these measures.

The next slide is just looking at nonres, so we’re looking at lighting, chillers, and a split package

AC unit. And we see the same kind of relationships we saw before. The mid-case is very close to the current, with a little bit more of a bump for the HVAC.

The 40-percent case is pretty close to the mid-case and then we'll go up with our low demand/high efficiency case, and then the highest would be our high GHG case.

Okay, the next slide is just on nonres 30 we're seeing the same relationship, so I'll go ahead and just skip over this one.

So, those are the scenarios, so that's one of the things we've been exploring.

The other thing we've been thinking about or actually have heard some feedback about is our T&D allocation factors, and perhaps changing those.

So, to give people background, the current way we allocate T&D is we use temperature as a proxy for peak loads. So, the higher the temperature we assume the higher the loading, and the more you need -- or the more valuable reductions would be during those times.

Now, some parties in other proceedings, especially things like the NEM, the Net Energy Metering proceeding, have noted that in a lot of cases that high temperature, you know, sort of mid-afternoon, that's not really when they're seeing the peaks on their systems anymore, or at least on certain circuits in their system.

There are a lot of cases where they're seeing like late afternoon or early evening peaks, especially for commuter communities, you know, mostly residential circuits.

And so, the question's been raised, well, could we replace this temperature information with actual utility load data?

Because this temperature information, this goes way back -- or this methodology goes back to the original, you know, 2005 standards when we just didn't have good hourly utility load data, and so the temperature proxy was the best we could do.

Now, there are some issues with even trying to use the utility load data. One is the fact that we would need to adjust that actual data to match our weather data. Right, because we don't actually know what the loads would have been given our CZ 2010 weather -- or CT 2010 weather files, so there would have to be some adjustments that happen there.

Also, we're doing things at the 16 climate zone levels so once you start averaging or aggregating all of that utility data up to the 16 climate zones, you may not really see these big differences anymore. You may not see that residential, like 7:00 or 8:00 p.m. peak, because it’s now blended in with some commercial that’s peaking, you know, mid-day and so maybe that effect really doesn’t show up.

Now, because of that, well, maybe a thing to consider is maybe we do a different set of allocation factors for res versus nonres because res customers are probably on circuits that are primarily or predominantly residential, anyway, so maybe you have a circuit there or use allocators that reflect that late kind of afternoon or early evening peak for res. And then you have a separate set of allocators for your nonres that reflects more of the standard kind of commercial mix.

And I noticed a lot of people sort of pondering and thinking about that. And that’s good because we don’t really have the answers at this point. We’re more sort of posing the question to the group.

Now, let’s see, I guess I’ll mention that if we do use load data, the way we would convert that into allocators is using something called the peak capacity allocation factor method. And that’s where we just allocate capacity to those hours that have the highest load levels.

And this is something that’s, you know, very traditional. It’s been used in utility rate making, their marginal costing for decades. So, we're confident with the methodology, it's just a matter of whether we can get the data to apply it to and whether that even makes sense given some of the issues and constraints around the data.

Now, to give you an appreciation of, well, what kind of impact would this have, we put out a few climate zones where we actually were able to estimate total climate zone load data, given some other projects we'd worked on.

And so this one here, we're looking at Pasadena. The current TDV factors are in blue and that's compared to what we would get the peak caps, which would be the load-based method in red.

So, you see for this one, or for this weather station it's really not that huge of a difference. I mean the peak caps are a little more concentrated, they're a little sort of spikier. But they tend to be sort of assigning the highest value to the same kind of hours that the weather method is doing.

And, frankly, that's comforting because this why we sort of came up with the weather proxy method was to do this kind of approximation.

If we look at Sacramento, we see the same sort of thing. It's a very good alignment. The peak cap, again, is a bit peakier so it would provide or assign more value to the sort of the narrow peak, not as much to the shoulders. But, you know, again, they do align pretty well. So, that was the good news.

The troubling thing is if you look at something like the L.A. area, so looking at the LAX weather station. Now, you see kind of this difference where the TDV factors and the peak caps are having their peaks, you know, about two hours apart.

So, based on the load-based method, the peak caps, you would actually want to be sort of assigning your peak values about two hours later than the current weather files are assigning.

And I think if we were able to break our peak caps into like residential circuit versus nonresidential circuits, we’d probably see the residential circuits shift even later. You know, maybe even a couple hours later.

You know, again, we don’t have the answer right now on whether this needs to be done but we wanted to at least present, well, what kind of differences are we currently seeing, at least at the total climate zone levels, recognizing that if it’s deemed important to recognize those differences even further, there may be a way to do that by breaking up into a res/nonres sort of distinction, as well.

Okay, so that’s it for our formal slides. We obviously have time for questions if anyone -- I guess, should I turn it back over to you, Joe?

MR. LOYER: Yeah, why don’t you grab a microphone at the chairs there, and I’ll take a look and see online.

MR. HORII: Okay.

MR. LOYER: If anybody in the audience would like to come up to a microphone and make comments or questions, I think we can start from there and then I’ll move to the people online.

And if you could just start with your name, maybe affiliation?

MR. TUTT: Good morning, this is Tim Tutt from SMUD.

And it’s my understanding that these TDV values are going to be used for the 2016 building standards for the next few years after that, I suppose.

And I’m looking out 30 years from there and it’s 2047, 2046, 2048, and that’s dang close to 2050 when we’re supposed to be significantly different in terms of the energy that we’re using and the load shape than the basic assumptions that go into this analysis.

So, I guess my question is or my recommendation is that you look at a scenario that takes the State's Scoping Plan that's being developed and carbonization or de-carbonization goals much more into account.

If we're going to be locking in savings values and technologies starting in 2016 that are going to be here 30 years from now in buildings, we might be locking in things that are actually antithetical to those goals that we're trying to achieve.

Right now it seems, for example, that many of the studies looking to 2050 talk about significant need for electrification of things like solar water heating and space heating, with high-efficiency heat pumps.

And it's our understanding that under the current TDV values and under the -- I presume under the new ones that you're developing, those technologies are still fairly disadvantaged.

And so, are we going to be wanting to see those in a retrofit application for the buildings that we're designing in 2016 and 2017 when we get out to the time when we need that energy?

I guess, and then the other question is with respect to the penetration of renewables and the de-carbonization of the grid we're already seeing, in some of your firm's other work and in, you know, information at the Cal-ISO, the famous duck chart and negative pricing in certain hours of the day during the spring and winter months.

And I just -- I don't understand exactly how that negative pricing gets reflected in the TDV values or if it ever -- if it does.

And so, is that something that could be brought into the analysis to show, then, that there might be a benefit to have green technologies installed in buildings that are able to provide load during those hours when there's negative pricing, or when the ramping is happening?

But it would have to be controllable. It would have to have some demand response aspect to it because you might not want it to provide load in August, when you might want it to provide load in March.

And then, the other question I have and I guess it may be a similar thing, I don't know how electric transportation fits into this, but we also have pretty significant goals for electric transportation in the State.

And I know that at least in some of the green building codes that go beyond the standards there's the beginnings of looking at requiring or examining electric transportation measures or installations.

And that's an example of a load which you might want to be able to control, but you might want to be able to incentivize in buildings that they have those technologies available for that control, for that load to happen in the March mornings and not happen in the middle of the summer.

So, thanks.

MR. LOYER: Yeah, I don't think -- I think if we -- do you want us to respond to that, Tim, or do you want to just make your comment or -- you ran away from the mic, I wasn't sure if you were just going to leave the comment or if you want a response?

MR. TUTT: I'm happy to do either.

MR. LOYER: Okay.

(Off-mic comment)

MR. TUTT: Absolutely and I want proof.

MR. LOYER: I think for the most part when we're looking at this TDV we're very early on, as we've said.

I think some of the carbon-neutral or even carbon-negative technologies, like ground source heat pump and the like, I think in particular ground source heat pump. I've had a lot of dealings with that in the past. It has a lot more to overcome than just this.

I think if we look at examples like the installation over at the Honda House that's very exciting, I think that's a -- that's not a new application of that particular technology, but I think that's a demonstration that that technology can overcome its problem that it's had for the last, I'm going to just throw it out there, 50 years of having a high initial cost issue.

I think that -- I think those kinds of technologies, carbon-neutral and carbon-negative technologies are going to be winners as we move forward.

But the TDV has to be made on a fair basis and it has to value things on a fair basis. And that, of course, leaves the door open for incentives from utilities later on to move those technologies more into the market and to make them more palatable and more cost effective.

I don't think this TDV gets us all the way there and I don't think it was ever intended to.

MR. TUTT: Yes, so thanks. I considered installing a ground source heat pump during a remodel at my house and I ran into the same barrier I think that you're alluding to. And that was that my wallet wasn't big enough for that.

MR. LOYER: Absolutely, yeah.

MR. TUTT: But we're not so much thinking of that. I mean that's part of the picture. But if you look at the advances in heat pump technology, you have electric heat pump water heaters and other things that are getting fairly cost effective these days.

And it’s my understanding, without knowing the details, that those technologies are still somewhat disadvantaged in the TDV calculations.

And I’m not -- I just want you to take a look at that as we move forward.

MR. LOYER: I think we can do that.

MR. TUTT: All right, thanks.

MR. RAYMER: Thank you. I’m Bob Raymer with the California Building Industry Association.

And before I get into some general comments, just with regards to EV charging it kind of struck me that, you know, without the Smart charging technology there could be some significant issues with the 6:00 peak.

But having said that, just for background on what’s coming in the code, starting in July -- well, I’m assuming, you know, right now there’s probably just slight under a 100 percent chance that HCD’s going to be adopting EV-ready requirements for all new single-family dwellings.

That’s going to be kicking in, in July of 2015. We are getting this done about 18 months early. It’s part of the Governor’s Executive Order.

And without getting too far into the standards, we’re going to have sort of a larger electrical panel with some empty plug slots and the conduit. Effectively, we’re going to be putting into every home certain things that are just going to make it far less labor intensive to put in EV charging down the road, as opposed to putting it into an existing dwelling.

So, with that being stated, I don’t anticipate a huge surge in EV charging in July of 2015, but I suspect as you get into 2017 and 2018 things are going to start moving a lot quicker, at least with the new residential construction on that.

Now, getting into today’s presentation, you know, having been a student of the regulatory process for a long time, back to the early 1980s, the CEC and on a very nice point has this meeting on a very regular basis every three years. The last time we did this was like November of 2010, I believe.

And it strikes me that time after time the longer we get in this, and the smarter I supposedly am, the stupider I know I am.

The fact of the matter is I feel like a deer in the headlights right now. There is just an enormous amount of information, synergistic effects of this that could have an impact on that.

And the bottom line, part of the job that Mike and I have to do for CBIA is that we have to try to get information out in a way that's usable and doesn't cause someone's eyes to glaze over in the first 30 seconds of the conversation, or in the case of today's conversation, the first five seconds.

And so, you know, ultimately what we're looking for is an ability to somehow at least ensure the building industry, the contractor, the builder, the designer, the building official, the homebuyer primarily, and to some extent Legislators because they're beginning to ask some questions that I haven't seen them ask in probably 25 years. And that's another issue if somebody wants to talk to me offline.

But we have to be able to look the homebuyer in the face and say you're going to get your money back. A very simple observation, a very simple goal, you know, which is sort of embodied in what is in Public Resources Code 25402.

But the bottom line is we're going to take the house that we're building today and we're going to add some stuff to it. And, at a minimum, over the 30-year life of that residential dwelling you're going to get your money back in lower utility bills. And that's always been sort of the common thread here.

And so, once again, I don’t anticipate getting answers to a lot of the questions I’m about to ask.

But we’re going to be very interested as we go over this process over, particularly, the next five to six months, but over the next year because we’re looking at adoption happening in probably the second quarter of 2015.

Will the homeowner get their money back over that 30-year life cycle?

You’ve already answered some of the questions about the differences between 2016 and 2013.

There’s also some interesting challenges that this particular update’s going to have that most of the previous updates didn’t.

With the exception of a plumbing proposal that was proposed for the 2013 regs, you’ve got two items that the Energy Commission is going to be looking at for residential dwellings. Particularly, the advanced wall systems and the high-performance attics, that both represent enormous departures from standard construction design.

Yes, they can be done. Yes, we’ve got examples of them being done and being done well, to a lesser extent for the roofs, more of an extent for the walls, having more appreciation of that.

But still, both of them, even the examples we have are few and far between.

And so, on a positive note, we know that the Energy Commission staff is well aware that both of these represent major shifts in designs. And that, in turn, is going to prompt requirement for time and education on the part of the design professionals, code enforcement, the site superintendent, the contractors, the product manufacturers.

In particular, with the advanced wall systems we had an energy forum a few weeks ago and we heard some very clear concerns that, yes, they can certainly move their product design lab. In essence, the extruders, the fabricators, all of the machinery, the retooling that has to be done will cost, you know, X number of hundred thousand dollars per machine and per plant. They can definitely gear up for it.

What wasn't discussed is the fact that they still have to maintain the ability to produce the existing products, you know. For those existing, you know, 13 and a half million dwellings that are out there right now, they've still got to be able to produce products that meet that goal.

So, in essence, we're looking at not only retooling, but the expansion of product line and facility.

That represents an enormous cost that’s going to be very difficult to put a financial or economic value on that type of a change.

And the question here is just like the window changes that we saw in 1992, by the time we hit ’96 and ’97 things had kind of smoothed out. By the time we hit the ’98 update vinyl windows were here. It was no big deal anymore.

But in 1993 and ’94 it was a huge deal. There were some companies that had a very rocky start. A couple that I understand went out of business.

The question here is how is the Energy Commission staff going to be able to, you know, be anywhere in the ballpark in trying to determine the sort of differential economic impact that it’s going to take to get all of these individuals up to speed, to get these companies to change product lines, to retool and then to, finally, smoothly be where the CEC wants to see things and where they will be down the road.

In essence, we’re going to have a huge hump, you know, starting in 2017 that’s probably going to last three to four years because we’re looking to try to do a whole lot in a very short period of time.

And so that, in particular to previous updates, I think that is going to present an enormous challenge for the Energy Commission.

That being said, unlike a lot of previous updates we would like to help provide more and higher quality information as the CEC goes about that.

And to that I would like to offer to the CEC for the first time we're going to try and get some of our large production members, and we can't go out and ask this every other week, we're going to have to limit to maybe one or two times where we seek certain information.

But what we'd like to do is provide a base house, where here are the current standards, here are the 2013 standards, here's the house, the design that you would normally be working with now.

And here is the two or three most common foreseen scenarios of going to advanced walls and of going to high-performance attics.

And what we would like to know is in your building dynamic what are those costs?

And so, in essence, we'd like the CEC to help us ask our members the right questions early on in the process as opposed to the day before the standards get adopted so that, you know, we've at least got some quality information to work with.

Understanding everything that happened this morning is incredibly difficult. But the fact is what you’re talking about is what will go into the black box that we put a lot of input variables in and then out at the end of the day it will say, well, yeah, this measure makes it or that measure doesn’t.

I’m not going to try to explain to anybody what’s in that black box because, quite frankly, I don’t have a good handle on it.

But at the end of the day we want to make sure that at least the input variables going in are solid and we can get some usable data at the end of it.

Okay and this was an odd question that was brought up in the Legislature recently. There was a bill proposed that was trying to put some type of a plus or a minus on the accuracy of the Public Domain Program.

We had some productive input on that. That portion of the bill has been ripped out. It no longer exists.

But during that debate there was a discussion about how the CEC goes about judging the accuracy of its standards as it’s been developed over the past 20 years.

And while that’s of more of interest to some Legislators than most of them, I would assume most of them could care less; there are some that have a growing interest here.

And so, it would be good if we could find some way of sort of judging how things have gone over the last -- particularly the last decade. Are we really reducing energy consumption or are the changes that we’re making in the envelope being eaten up by a growing plug load?

That is the type of useful information that perhaps the Legislature had.

But to bring this to conclusion, we’re going to be doing what we can early on, during the latter part of the spring and throughout the summer to get you some quality information.

But like I said, we can’t go to the large builder members dozens of times. We’re probably going to have to limit it to a one or two-ask questions to get this done.

So, with that thank you for your time and maybe in 2017 we can find a way to make this simpler to understand and go back to six factors.

MR. LOYER: Yeah, Mazi, you want to respond?

MR. SHIRAKH: Yeah, just briefly. We like your offer of providing a forum for the builders and the staff to exchange ideas. I think that’s a great start.

And again, to follow on with the April 4th meeting, you mentioned a few of the ideas. One of them is to have different windows to accommodate the two-inch continuous insulation on the outside.

And we'd like to pursue that with the builders to see if that's an option that they would even pursue before we talk to you. And I think I exchanged some e-mails with Mike about that.

You know, we can approach the window manufacturers and we have actually investigated that a little bit ourselves.

It seems like it is a thing that they can do to build, the window manufacturers with the frame, you know, where the fin is.

By relocating that, you know, you can have a frame that would accommodate two inches.

But is this an option that builders would pursue if we provided it.

MR. RAYMER: Is it a viable option on a large-scale basis?

And what I was taken aback was, you know, I heard -- you know, during that April 4th forum the one most negative comment I heard at the mic was from the window industry, and particularly the retooling costs and the ability to -- they've also got to manufacture the existing product line in addition to a new product line.

I was surprised to hear afterwards that at least one of the reps was indicating we can do this.

I plan to contact one of these -- the head of AAMA to try to get a better handle on this.

Because just like with builders on various designs out there, I can talk to a manufacturer, whether it’s insulation or whatever, and I can get diametrically opposed responses to the same question, and that’s not usable.

So, in essence, I can find probably two window manufacturers real quick that will tell they absolutely can’t do this and one to say of course we can do that.

Okay, it’s just we’ve got to have enough time and effort to move into it, but we can do that.

Others will say, no, it will kill us.

And so, how do we take that and figure out, you know, how much of it is absolutely truth versus, you know, what is something that maybe if it’s a longer period of time that’s going to work out?

And so, that is going to be the real challenge here. Because the last time around with the 2013 regs, sort of one of the huge design issues that was being discussed was the plumbing layout, you know, for hot water and to try to move to reductions of the one-inch line, have more a spider type of a design as opposed to what we currently have.

And while that was ultimately removed, the high-performance walls and the attics are, you know, on a scale of one to ten those are 11 compared to what the plumbing thing was.

And so, this is one enormous challenge. The question is how do we quickly get the quality information?

And so, like I said, I want to limit the amount of times that we go to the well, you know, asking for this because after a while they'll just say, oh, it's another e-mail from Raymer. He wants more information, to heck with that.

And so, we'll work with you, we'll focus on some target audience, you know, one or two, and then that way we won't basically wear them out, you know, because they've got their other jobs to do, as well.

MR. SHIRAKH: I understand.

MR. RAYMER: So, we look forward to helping on that.

MR. SHIRAKH: Just one additional point on the windows and the insulation. It was the rep that came to me after the meeting and he said -- his request was that we can make any window, but he wanted us to limit it to only one option because of the cost and all the other implications.

MR. RAYMER: Yeah.

MR. SHIRAKH: So, that’s what he told me.

And the other thing is that this is only one of the options on the table for advanced walls. So, that’s kind of important to keep in mind because there’s two-by-six walls, there’s staggered stud, there’s double walls, there’s all sorts of other ways of meeting this requirement.

And we’re not looking for unanimous consent from all the builders or the windows manufacturers, as long as there’s enough interest in some part of the market to utilize this option, among others, you know, different builders, manufacturers will gravitate towards different solutions.

If there’s enough demand for it, that’s something we can pursue.

MR. RAYMER: I’m looking at this --

MR. SHIRAKH: And we’re actually relying on your advice and judgment on this.

MR. RAYMER: I’m always looking at this. It’s not a three-year change. I’m looking at it in terms of three, six, nine years kind of getting it out there.

MR. SHIRAKH: Right.

MR. RAYMER: So, I’m already kind of looking at 2023, or whatever.

But the fact that you’re providing the solar option, I realize there’s going to be some debate over that, but the solar option helps take some of the steam out of the kettle so that you’re not forcing, by 2017 you absolutely have to do this, this and this, you’ve got a variety of options.

That helps make this move forward in a nice calmer fashion.

MR. SHIRAKH: Fully aware of that.

MR. RAYMER: And so with that, what I found odd about the window manufacturer’s response is that I think some of his own membership would hang him if they knew, yeah, that had been said.

Keep in mind, you’ve got 13 and a half million existing dwellings that already have their envelopes established. A very cost-effective thing that could be done is to go to the low E glass. You know, change out the system and in many cases you’ll be putting in a new frame or whatever with this. It’s a very kind of easy way to go about this.

They’re going to have to continue manufacturing that product line. It’s a very viable, very market driven thing. And so, they’re effectively going to have the duality here where they've got their existing stuff for the two-by-four wall construction and then they may have the newer product line.

Some companies will probably specialize in having that only as their product line, as opposed to those that try to address all of the market needs.

So, you know, once again, by allowing us a lot of options as we go into 2017 to 2020 that helps sort of, you know, take some of the urgency to get up to speed on just this right away.

MR. SHIRAK: I understand.

MR. RAYMER: And so with that we're very grateful and we'll look forward to working with you on it.

MR. SHIRAKH: Thank you, Bob.

MR. RAYMER: Thank you.

MR. MC HUGH: Hi this Jon McHugh. You know, this is about time dependent valuation, what is the cost savings side of the efficiency measures. But I feel like I'm sort of obligated to respond to the comments about costs.

If you look at the last round of standards, there's thousands of pages of data collected, hundreds of interviews.

If you look at the last round of standards, besides the work that the Codes and Standards Program did, there was also a series of conversations with the California Energy Commission.

And what we found was actually that the costs that the Energy Commission were using and the costs that your consultant, ConSol, provided, they were extremely close together.

So, it’s really not a question about cost as a question about political will and some of the other things that were involved with that standard.

So, I just actually want to set the record straight. We will be collecting information. We have been collecting information. We are working with builders. We have programs with builders where we’re collecting information from them. We look forward to working with you and also getting your aggregated information.

But we also go directly to the builders and are collecting real costs from real projects, both in terms of demonstration projects and also mass-produced projects.

I don’t want to delay the rest of the discussion and I’ve got some additional questions, but I’ll wait until other people have time to talk. Thanks.

MR. NESBITT: George Nesbitt. I’m a HERS rater.

The first question is my understanding has always been that the output from PV systems peaked before the system peak? Is that -- kind of what you presented was saying that as we bring more renewables online the peak is shifting later and later.

Is that only because as we bring more on it does shift it or is it because they don't align?

MR. HORII: Well, the shifting is really caused because the large amount of PV, basically, it's going to drop the load down during sort of the midday, and so the net load that's leftover is going to be sort of occurring later and later as you see that PV output happening.

MR. NESBITT: Well, and as the PV goes down, the system has to --

MR. HORII: Right.

MR. NESBITT: -- ramp back up to get --

MR. HORII: Right, yeah, you need other sort of resources to match that.

MR. NESBITT: I wonder to what extent people are thinking about, well, shifting loads. Maybe we want to shift loads earlier than later, just as a concept. Use it when you've got it.

But sort of the -- there's a lot of different metrics we can use to look at energy, the site energy costs, source energy, TDV. You know, God knows, greenhouse gases and whatnot. And they each give us different answers.

And I wonder to what extent -- TDV, I think, is very focused on peak cooling load and to what extent at the expense of everything else?

Although, obviously, peak load is a very important thing and even though per capita we've been pretty flat on consumption, our per capita has gone up. So, certainly, our demand on the system has kept going up.

We are contemplating electrifying the transportation system, people want to go net zero energy or zero net energy, which is leading people to think, oh, I need to get rid of the gas and go electric.

Yet, the trend nationally has been ever-increasing electric consumption, which has meant source energy has skyrocketed.

And so, TDV is definitely, I think, biased against electricity, even heat pumps.

My modeling has generally been that it's pretty hard to get a heat pump with an efficiency that can compete with, say, high-efficiency gas. It is a penalty, although maybe slight.

So, we've got sort of competing, you know, use more electricity, yet we’re going to be -- we’re constrained. I mean, we can’t just double and triple the grid.

And so, I’ve made the comment in the past, too bad Martha left earlier, but I’ve said, can you save time-dependent value energy but actually increase energy use?

And the answer, quite frankly, is yes. What I’m seeing is the non-air conditioning climates becoming more and more like they look like they’re more of an air conditioning climate.

And I just recently ran a calc on a project where we replaced or the client replaced double pane aluminum windows with vinyl, typical low E, you know, .29, maybe lower than that. And sure enough, it saves like five and a half percent time dependent value. But almost all that’s air conditioning.

This is Oakland. Nobody has air conditioning. Nobody’s going to add it. And the heating energy use went up.

So, you know, we’re so focused on that peak, as important as it is, there’s other energy to be saved. Perhaps we really care more about greenhouse gas reductions, per se. But it’s just -- you know, I’m not sure any one metric is perfect. Certainly, source energy is biased against electricity.

Most people care about the dollar value of their bill, although I don’t think higher bills are always an incentive to do something.

Some people will believe until they -- you know, they don’t know what to do often.

So, I’m just kind of just -- you know, TDV has good points, but I’m not sure if we’re always focused, you know.

And I think TDV, you know, you mentioned, I think, sort of TDV looking at cooling. But when we run a calc it’s all the energy use. It doesn’t care whether it’s a light or refrigerator, or the air conditioner. It’s what time of day are we assuming energy is being used.

So, if we say lighting energy or refrigeration energy, we are saving energy and reducing the peak. So, in that sense, even though it’s very dominant on cooling and cooling is a bigger load, you know, so it’s just -- I think, ultimately, we need to make sure we’re saving energy and all energy, otherwise we’re not getting where we’re going.

MR. SHIRAKH: If the question is on the TDV, we can use dollars, but use more energy. I think the answer is yes.

If the question is, is there something wrong with that scenario?

And that’s the whole point of TDV that when you have those multipliers that range from 1 to 200, depending on the hours of the day and time of the year, what TDV is suggesting is that there’s time of the year, times of the day when that unit of energy is worth a lot more.

And if you can save that, but in exchange use a little bit more energy off-peak, we’re saying that’s okay.

And that’s what -- and if you look at a thermal energy storage system that’s what it does. It saves energy on-peak, but it uses a little bit more off-peak.

So, I don’t think that’s really a fatal flaw of TDV.

MR. HODGSON: I have a series of questions, just from my own background so I can understand. This is Mike Hodgson, from ConSol.

And I’d like to look at Eric and Brian’s presentation, I think it’s slide 21, which is on the decomposition for electricity, talking about price. That one right there, thanks Joe.

And I’m trying to -- this is to educate me, all right.

MR. HORII: Okay.

MR. HODGSON: So, I'm trying to understand the impact of greenhouse gas on this price of electricity for TDV, right.

And I'm looking off-peak and I'm looking at the emission portion of it, and I presume that's what greenhouse gas would be, right?

MR. HORII: Right.

MR. HODGSON: So that's like -- and I'm estimating this and don't get me too many decimal points here. I'm looking -- it looks like about 25 out of 150. I call that 17 percent. Pick a number, 16, 17 percent.

And then if we go over to peak, the emission line seems to be relatively flat. It's not, you know, time dependent. And then it's that 25-unit out of maybe 300, so call it a little less than 10 percent, or about that.

So, I just want to understand that?

MR. HORII: Okay.

MR. HODGSON: So --

MR. HORII: Do we talk about that before we go on to your next one or --

MR. HODGSON: No, I think I'll get to where I'm going to go, okay.

MR. HORII: Okay.

MR. HODGSON: So, I just want to understand if I’m looking at the right thing. And so that’s -- I’m just trying to figure out what the impact of greenhouse gas is on TDV.

And so, the estimates that you did and I believe that the CEC has done, I think Angela, your predictions were assuming that greenhouse gas would be in the mid-level and then you had a scenario that was -- or I’m going to call mid-cost level, and then the scenario in the high-cost level. Is that correct?

MR. HORII: Yes.

MR. HODGSON: Okay. So, in trying to prepare for these meetings in which both Bob Raymer and I are not -- this is not the area that we swim in very frequently, I tried to look at some of the papers that were published that the CEC put on the website.

And the one that was by Bornstein that came out, and not that I’ve read the whole thing -- I read the abstract and the conclusion. That’s how I read these things. It was 50 some odd pages of stuff.

And I think the conclusion was that the greenhouse gas level is really low. And I think they call it at the basement or the price floor.

So, I’m wondering as a scenario, and that’s what you were kind of asking today is have we covered the scenarios and the range?

We have a mid-scenario and we have a high scenario. Should we do a low scenario?

I mean, the paper that you cited as one of the background papers, to me, as a person who's not familiar with this area, so tell me if I'm off base, says the greenhouse gas levels really are the low scenario or very close to their price floor.

So, I'm just wondering, if we're trying to figure out cost effectiveness over time, and we have kind of the mid and high range of 10 to 20 percent of the impact of TDV, should we look at the low range, too, just so we have the full range?

So, that's my question. Am I -- does that make sense?

MR. HORII: It does. And, you know, one of the things I'll point out from a practical perspective is if we, you know, were to use -- well, I guess I should start out that sort of a theoretical basis it tends to make sense, you know, to have that symmetry.

MR. HODGSON: Right.

MR. HORII: But as far as an impact basis, it's probably really not going to have much of an impact because of that rate adjustment.

So, unless, under that scenario it's believed that rates would change, which it may not really change because of the way those Cap and Trade sort of fees get refunded back to customers anyway, it ends up sort of being a wash.

MR. HODGSON: Uh-hum.

MR. HORII: Maybe the energy piece changes a little bit. Maybe the emissions piece goes down. But that rate adjustment would just go back up to compensate, so the total TDVs may not end up being significantly different.

MR. HODGSON: So, I'll take -- the conclusion from what you just said, then, is that really the impact on greenhouse gas is relatively insignificant or neutral?

MR. HORII: No, I'm not saying the impact on GHG. I'm saying the impact on our TDVs. Because remember, our TDVs were always chewing back up to the rate level.

MR. HODGSON: Okay.

MR. HORII: And that rate level isn't going to change under that scenario, or if it changed it would be very small. So, it wouldn't really have a significant impact.

MR. HODGSON: Interesting. Now, I also understand that policy is different than cost. So, the

State is trying to do policy and so it may be smart to do high GHG levels in policy.

MR. HORII: Uh-hum.

MR. HODGSON: But from the building industry, we look at things as being cost effective. So, we have to explain to our clients whether or not this is going to pay for itself over time.

And so, I'm trying to also try to figure out the impact of greenhouse gas and then in rates.

MR. HORII: Uh-hum.

MR. HODGSON: And is that also shown in this or is that implied already in the rate structure?

MR. HORII: It's buried into the rates already.

MR. HODGSON: Okay. All right thank you.

MR. HORII: Okay.

MR. MC HUGH: So, I'm going to get to probably a question that's probably of real interest for Bob, and you can probably tell me.

One of the questions is does -- you know, what's actually happening with the TDV costs? Is this -- is the real value of gas costs and electricity cost increasing, decreasing as compared to the last round of TDVs?

MR. HORII: Well, the costs -- I mean, are you looking at that --

MR. MC HUGH: The present -- the total present value cost when you do these calculations?

MR. HORII: The gas or the rates, though?

MR. MC HUGH: What?

MR. HORII: Of the sort of gas costs like going to generators or the actual sort of gas rate level?

MR. MC HUGH: No, no, no the actual. You know, so what I think Bob's interested in, you know, are people, when they look at the savings of a given measure, and I know the answer's going to change, of course, by measure.

But on average, if you look at the realm of things that will either increase or decrease energy consumption, do the TDVs increase the real value of cost for this proposed 2017 TDVs -- will the present value be higher in real dollars or will it be lower in real dollars, or will it be essentially the same?

And I -- I think that's --

MR. PENNINGTON: I think that's a good question. So, your comparison curves --

MR. MC KINNEY: Can you come to a mic, Mr. Pennington?

MR. PENNINGTON: So, Brian, I think you've been using curves to answer your question. That's all I was going to say.

MR. HORII: Yeah, I think like slide 13 --

MR. RAYMER: There's a lot of details and you want to know at the end of the day what's the comparison.

MR. HORII: Okay, yeah, it's a little small to see.

MR. MC HUGH: And that's some nominal rates, right, so --

MR. HORII: Right, so these are nominal.

So, the dash lines are the current standards and the blue is nonres, and the -- I'm sorry, the blue is res, the red is nonres.

So, one of the things you'll see is res and nonres in the current standards are very close to each other and you can barely even distinguish them on the chart.

But the new rate forecast actually has nonres substantially lower than res.

So, I would say that the res is very comparable, but the nonres we do see a bit of a drop.

MR. MC HUGH: I see. And I see this as a time stream, but if you present value them that's -- oh, I guess I see what you're saying.

MR. HORII: Yeah, and if you -- you basically get to the same --

MR. MC HUGH: The same okay. Great, I think that’s probably really useful.

MR. PENNINGTON: And then you have a curve for natural gas, as well?

MR. HORII: Yeah, the gas curve is, let’s see, slide 6. Yeah, and it’s the same sort of relationship. Again, the res and the nonres, the dash lines are very close. So, the res looks pretty comparable when you look at the solid blue versus the dash.

But again, our new nonres gas is substantially below, just like we saw on electric, so that’s where you’ll see that change.

MR. MC HUGH: Okay, great, and I hope that’s helpful for everyone.

Now, for the weather data, you know, kind of going back into the weeds, just remind me, is this weather data -- is it synthetic so that it’s different months from different years or is it one year? Is it the same year for every climate zone? How is the weather?

MR. HORII: It’s different -- let’s see, for every month it could be represented by a different year, but that same year is going to be used across all climate zones.

MR. MC HUGH: Okay, great. Okay, that helps me understand that.

And when you talked about having separate peak caps by residential versus nonresidential, I would expect that the impacts is different for distribution versus transmission, so you're going to -- right that --

MR. HORII: Yeah, that's a good point. And that is one of the challenges is sort of what level of aggregation would you look at, would you try to represent sort of down at the circuit level closest to the customer or an aggregation of a bunch of circuits to be closer to a transmission level.

The costs we tend to see from the utilities are larger at the distribution level than the transmission, so I think it would be leaning more toward a distribution level.

MR. MC HUGH: Oh, okay, so there would be some benefit to breaking it out.

I also noticed that the greenhouse gas curve was flat and I thought I remembered that, you know, during the peak period there would be all of these, you know, pulling these power plants out of mothballs that have, you know, a really high heat rate, et cetera.

But, I mean, maybe I'm just missing it or maybe just there is an effect but it's a small effect. What's the --

MR. HORII: Well, there is an effect but it’s fairly -- I don’t know if I’d say small, but it’s fairly uniform.

If I can find that slide where we were showing, in 3D terms, Angela’s electricity -- yeah, on slide 22.

The GHG costs are pretty much going to be essentially proportional to our average energy costs. And you’ll see it’s pretty flat. I mean, you do have that peak in the summer months.

But one thing I’ll point out is when I was showing that decomp, right, I was averaging across all months for the hours. So, I think that’s why it looks flatter.

MR. MC HUGH: Okay. Okay, so it looks flat.

MR. HORII: Right.

MR. MC HUGH: So, there actually is an effect that actually makes the overall TDVs more peaky than you would have if you didn’t have the GHG.

But in terms of the total value, because you have the retail rate adjustment it doesn’t affect -- it doesn’t affect the total revenues that are projected for the future utilities.

MR. HORII: Right. And as far as the charts earlier, when we showed that decomp by hours, just remember we’re averaging across all those other months.

So, that little hump we see there in the summer really gets sort of smashed in the presentation on the chart.

MR. MC HUGH: Okay, now I understand.

And right, my understanding is that right now the GHGs are rebated back to the consumer. So, is this the unrebated GHGs that we're looking at or the rebated GHGs in this analysis?

MR. HORII: Well, we break out the GHG amount. But in the mid-case and low case it's not like an adder, it's just a component of energy price, but we just show it as a separate piece.

For the high GHG case, we actually consider that to be a non-rebated cost, so that actually is an additional cost.

MR. MC HUGH: Oh, okay.

MR. HORII: And that's why we see those.

MR. MC HUGH: Because that's saying a policy change.

MR. HORII: Right.

MR. MC HUGH: That the policy is to actually -- so, the consumer actually experiences the impact of the GHG costs. Okay, thank you.

Now, you show that the loads change in the near term versus the far term and, you know, so the whole -- you know, all the stuff that's been going with, what do they call it, the duck's back or something like that.

I'm assuming that that load shape has an impact on price suppression and the expected costs that are in your model.

So, are those measures that actually help reduce that peak, are we actually capturing that in the TDV that's reflecting that potentially we have some lower than what we'd expect future rates to be because we've actually spread the peak out somewhat?

MR. HORII: Theoretically, the rates should be reflecting the need for less capacity as you have these other resources sort of shaving the peak, albeit shifting them.

But it's just -- you know, it's not a precise science and so --

MR. MC HUGH: Right.

MR. HORII: I'm saying in theory it should be there. Whether it's really captured very well, I wouldn't want to --

MR. MC HUGH: Yeah, okay. Then let's see, so looking at this round of standards, I think we've heard a couple times from Bob about, you know, the ability to trade off with photovoltaics.

And for the standards are you expecting that, for instance for PV exports, that they would have the same TDV value as the reduction in imports that you see, you know, from an efficiency measure.

So, are you guys thinking about a fourth stream for PV exports or what is -- how are you planning on addressing distributed generation in TDV?

MR. LOYER: I think we're -- I think we're still trying to figure that out for ourselves before we really get too far into the public venue with that particular -- we're working with E3 to try and sort of run some scenarios sort of privately.

MR. MC HUGH: Oh, okay, so that's still in analysis right now?

MR. LOYER: Yeah, I think that's under consideration at this point.

MR. MC HUGH: Okay.

MR. RAYMER: This is Bob Raymer with CBI. A question for Jon, are you talking about where you're exporting to the grid during parts of the day or parts of the year, as opposed to just producing enough that's used internally within the dwelling, itself?

MR. LOYER: That's what I took that as.

MR. PANDE: Abijeet Pande with TRC. And building on that question, the other question I had was all of the scenario analysis right now is with RPS, right? What happens to all the rooftop solar that's been added or predicted to be added? How does that change any of the load shapes and potentially, you know, the time factor as you were talking about the peak shifting and so on?

And you will see more of that pronounced as we have more rooftop solar on this market.

MR. HORII: You know how much rooftop is in the IEPR?

MS. TANGHETTI: For the demand forecast there is about 4,000 megawatts installed by the year 2024, so it does meet the California Solar Initiative.

So, that is already embedded in the demand forecast and the peak and energy are adjusted by that already for that.

There are additional amounts that we model that I showed you on the supply side, which do -- we do put a shape in and it does affect the peak in energy, and that's why we're seeing some of the shifting of the peak to different hours.

MS. GUPTA: Smita Gupta with Itron. Again, to add to that, another thing is about storage and the CPUC's, you know, directive on more distributed storage. Has that been also factored in because that's going to have a huge impact on shifting the peak, as well?

MR. CUTTER: So, the storage in the storage mandate has only just begun to be included in the 2014-15 TPPP scenarios. So, they're not included, yet, in any of the PLEXOS runs to date.

And I think there's still quite a bit of work to be done to understand exactly how the different types of storage and the applications would be translated into a unit in the PLEXOS model, and translated into a load shape or an impact on a net load shape.

So, we're not quite there, yet.

MS. PANDE: Abijeet with TRC, again. Angela, to your point, I'm just trying to understand the numbers. So, the slide you presented had solar, but that was all RPS solar?

MS. TANGHETTI: Correct, the slide that I presented was only solar that counted towards the Solar Initiative.

Embedded in the demand forecast that I showed for 2024 there is an embedded amount of installed PV and that's already deducted in those numbers that I showed there.

Within the demand forecast it will show you exactly what it deducts as far as a coincident value, as well. I think what I quoted was probably the installed number.

But for the impact at the time of system peak it’s a different number than that.

MR. PANDE: And that’s in the demand forecast?

MS. TANGHETTI: That’s posted in our demand forecast, in the forums.

MR. PANDE: Okay, thanks.

MS. TANGHETTI: Sure.

MR. LOYER: Seeing nobody else rush to the mic here, I’d like to open the comments up to the participants online. If you’ll send me a note before you unmute yourself, I’d appreciate that.

So, if there’s anybody online that would like to comment, please indicate now.

Seeing none, I think that draws this workshop to a close.

Remember that this is not the end of the conversation. You are more than welcome to submit written comments to our docket system. You can find that information on the notice for this workshop, which is on the Energy Commission website.

And I thank everybody for coming out today. Thank you.

(Thereupon, the Workshop was adjourned at 12:11 p.m.)

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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.

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