INTEGRATED ENERGY POLICY REPORT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	Docket No.
Preparation of the 2009 Integrated	)	09-IEP-1E
Energy Policy Report	)	
	)	

ORIGINAL

COMPARATIVE COSTS OF CALIFORNIA ELECTRICITY GENERATION TECHNOLOGIES

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, AUGUST 25, 2009

9:00 A.M.

Reported by:
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COMMISSIONERS PRESENT

Jeffrey Byron

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STAFF AND ADVISORS PRESENT

Kelly Birkenshaw

Laurie ten Hope

Ivin Rhyne

Gerald Braun

Al Alvarado

ALSO PRESENT

Richard McCann, Aspen Environmental Group

Charles O'Donnell, KEMA, Inc.

Pete Baumstark, KEMA, Inc.

Tony Braun, CMUA

Matt Barmack, Calpine

Kenneth Swain, Navigant Consulting

Evan Hughes, Biomass & Geothermal Consultant

Matt Campbell, SunPower

Raffi Minasian, Southern California Edison

Jim Farrar

Richard Murray, California Landscape Architect

Craig Lewis

I n d e x

I N D E X (CONT.)

P R O C E E D I N G S

9:00 A.M.

MS. GREEN: All right, we'll go ahead and get started. Good morning, I'm not Suzanne Korosec, that's what's stated on the agenda, there's a slight change.

However, I do work in the Energy Commission's IEPR Unit and my name's Lynette Green.

Welcome to today's IEPR Committee Workshop on Comparative Costs of California Electricity Generation Technologies.

The purpose of today's workshop is to review the Energy Commission staff's preliminary cost estimates for different electricity generation technologies.

The goal of this project is to have a single set of the most current levelized electricity generating cost estimates that can be used in policy development and energy resource planning at the Energy Commission and other State agencies.

Our agenda today will begin with a discussion of the goals of the analysis, followed by an overview of the actual analysis and results and then we'll open it up for discussion and comments, after which we'll break for lunch.

We'll resume with a presentation on Building and Community Scale Renewable Energy Technology Costs, again followed by an opportunity for public comment.

For those who are not familiar with the building, rest rooms are outside this room to your left, and we also have a snack bar up on the second floor.

And in the event of an emergency and we need to evacuate, please follow staff outside to the Roseville Park across the street and we'll wait there until we're told for all-clear signal.

Today's workshop is being broadcast through our WebEx conferencing system and parties should be aware that we are recording the workshop.

We'll make the recording available on our website a couple days after workshop and we'll also provide a written transcript once it's available, and it usually takes a couple weeks.

For presenters and commenters, please make sure you speak directly into the microphones so that people listening in on the WebEx can hear you clearly.

During the public comment period today we'll hear first from the folks in the room and then we'll open the lines to hear from WebEx participants.

For parties in the room, who make comments, please come up to the podium and use the microphone so we can capture your comments in the transcript.

It's also helpful if you can give the court reporter your business card when you come up to speak at the podium so we can make sure your name and affiliation are reflected correct in the transcript.

We're also asking parties to submit written comments and those are due by 5:00 p.m., on September 2nd. The information from this workshop will feed into the 2009 IEPR, the first draft of which is expected to be released at the end of September, with a hearing on the draft schedule for October 15th.

And with that I'll turn it over with the Commissioners for their opening remarks.

COMMISSIONER BYRON: Thank you, Ms. Green.

Good morning, everyone. I'm Commissioner Jeff Byron and I Chair the Integrated Energy Policy Report Committee.

Along with me at the dais here is my Associate Member of that Committee, Vice Chair Boyd. And his advisor to his left, Kelly Birkenshaw.

To my right is my advisor, Laurie ten Hope.

And I guess we could have called this a joint committee workshop since Commissioner Boyd and I are also both on the Electricity and Natural Gas Committee. However, it saved a little ink, I guess.

COMMISSIONER BOYD: It didn't save us at all.

COMMISSIONER BYRON: I can't believe that the last workshop on this subject, I believe, was April 16th; is that correct? It seems like only yesterday in some ways.

Commissioner, I often say when I'm speaking to some of my fellow Commissioners at the Public Utilities Commission, at least there's one commission in the State that's concerned about cost.

And, of course, that's not true, beside the Public Utilities Commission, this Commission is very concerned about the cost of generation, and for a couple of reasons.

One, it's extremely important that it be -- that there's accurate and readily available levelized cost of generation estimates for resource planning, but also -- let's see, I jotted my two down her, and the other that the information is available on a comparative basis.

That's oftentimes very difficult because the information might be from a vendor or for a particular generation technology, but we need to understand how those costs compare.

The staff's been busy making a number of improvements to their generation model, primarily in response to some recommendations from the '07 IEPR, that we asked them to look at a range of costs and, also, the long-term changes in cost, in certain cost variables.

So the staff's done that, they've looked at about, by my count, 21 different central station generation technologies, a number of natural gas-fired, nuclear integrated gasification plants, and a number of renewable technologies.

But I'll let the staff go into more detail as to how they would address the IEPR recommendations.

I look forward to an informative day, the presentations as well as suggested recommendations from those in attendance today.

And, Commissioner Boyd, would you like to add anything this morning?

COMMISSIONER BOYD: Very little, I hope. I said that to you yesterday and went on for five minutes, so let's see if I can be brief today.

You have captured the spirit of the notice, which in the notice the background was provided as to why we're here and what we and the staff are trying to achieve, you captured it well.

I think the last thing I would say is this is an extremely comprehensive report; I commend the staff for that.

It was, I'll admit it, laborious reading, but extremely educational. And so I look forward to the comments we hear today and any written testimony to see people's views, and point of views, and each suggestion they may have about what the staff has written.

But at the moment I stand most impressive and I think very educated, so this should be an interesting day.

COMMISSIONER BYRON: Yeah, the binder was tough, wasn't it?

COMMISSIONER BOYD: Yeah, it kept popping open on me.

In any event, the audience should know we sat here all day yesterday doing a different hearing. So I don't think we'll be testy today, but thank you for moving me to the left side today, instead of on the right side.

In any event, carry on.

COMMISSIONER BYRON: All right. Mr. Rhyne, you're up first.

MR. RHYNE: Thank you and good morning, and hopefully we'll be able to bring that laborious reading to life today.

First of all, my name is Ivin Rhyne; I'm the manager of the Electricity Analysis Office here, at the California Energy Commission.

And I'm here today to just start us off with a brief introduction to levelized costs of generation project for this IEPR cycle, and to give us some context about -- for the remainder of the discussion for today's workshop.

The project, itself, is a collaboration between several Commissions projects -- sorry, Commissions programs' consultants bringing together a pretty strong mix of technical expertise.

For the results of the study, the Cost Generation Study will support the development of the 2009 IEPR,and we've conducted similar analysis for the 2003 and the 2007 reports and improved the scope of the analysis each time.

This is a public domain model for others to use and we have many requests throughout the course of the year to make use of this and elements of this tool, not just its outputs but, in many cases, its inputs.

The project is one of the fundamental building blocks for conducting electricity resource planning studies and evaluations of the attributes of different generation options.

The Electricity Analysis Office undertook the task of updating and revising the cost of generation model. And as the Commissioner said, many of those updates were at the request of the previous IEPR Committee.

The primary tasks were to update the model inputs, study how factors change over time, include the effects of uncertainty in variables, a very important piece, and to produce a range of current and future levelized costs, rather than just a single point estimate of costs.

Now, we had several goals in mind for the project. And as I mentioned earlier, we did develop a model in previous IEPR cycles. We've used proprietary models in the past that were something of a black box, so we embarked on an effort to create an easy to use and transparent model, and transparency is really the key.

We wanted to have a tool that would -- that could functionally provide different levels of analysis. For example, we wanted a tool that could provide sensitivity estimates with varying input assumptions to understand how uncertainties may affect the cost calculations.

Another goal is to have consistent set of input assumptions that apply to different generation technologies.

We also wanted to easily create screening curves that could be easier to compare the different types of generation technologies operating at similar capacity factors.

Now that transparency idea is key in the next slide. This is a graphic that shows really seven different studies that can be used to kind of generate a range of costs across, as you can see, seven different technologies.

But as a colleague of mine, and one of the key authors of the reports says, the devil is really in the details.

It's difficult to actually do comparisons of these technologies because we don't always have access to the assumptions and even if we do, we have to wade through them and determine why and how different those assumptions are in each individual case to determine whether or not we're making an apples-to-apples comparison across these studies.

And so while the difference of the studies here does produce a range, it's difficult to discern the reasons for that range and to make valid conclusions for policy purposes based on that.

So rather than that, we've done this and this, by the way, although it's rather busy, is just an example of four technologies that had been used inside of a single model and then different inputs are varied across that. So this is called a sensitivity curve.

And the idea is that for each of these technologies, as we vary the inputs these curves show by what rate or by how much the output, the result changes. And this gives us a more effective and, we think, a more useful output rather than just multiple black box models.

So in this case, for example, we've changed things like capacity factor, range of installed cost, cost of debt, all of these inputs can change and as they change, they change the outputs.

One point I'd like to make here is that we would like to emphasize that there really is no single fuel price forecast that can always accurately predict pricing points in the future. And fuel, in many of these cases, is a really important input to the process.

A range of fuel cost is far more appropriate for any kind of project analysis. And we can also create cost curves that take into account those range of possible fuel costs.

We've also found that, contrary to what one would expect, when comparing similar models but with the same input assumptions the results really do differ, and sometimes by a large amount, because of varying levels of simplicity and different treatment of the assumptions. Literally, they're put together in different ways and, therefore, even with the same inputs you get different outputs.

This is the fundamental reason why I think a simple comparison of different levelized cost studies is really not -- is not effective unless it's done across a single model with a wide range of input assumptions.

So the application of the Levelized Cost of Generation Project, so there are multiple users of this project. Within the Commission it's been used as part of the Scenarios Project in the 2007 IEPR, the retail electricity prices, technology summaries in the Renewable Energy Office, transmission studies, and Title 24. It serves as an input for many of the things that we do internally.

But externally as well, outside of the Commission we have requests from the Legislature, from the California Public Utilities Commission to provide modeling, model evaluation or data, all of this is involved. We often get request from the ISO, the Independent System Operator, requests from consultants, developers, financial institutions to evaluate project investments.

Just to be clear, this is used not just in its outputs, but oftentimes its inputs and assumptions are just as important to those who are seeking this kind of information.

Now, the reality is that like any model, this model has limitations and we'd like to just make those clear up front.

Assumptions are variable and you can have high, low trend numbers, and in many of the figures we've shown you can see that the outputs really change a lot. And depending on which assumptions you choose, the output will certainly be different.

And in some cases you can't know how the system will affect the technology and vice-versa; you can't always know how the technology will affect the system.

And these are the kinds of things that in a perfect world, where we all had omniscience, these kinds of models would, of course, be unnecessary. But the reality is we have to make use of the pieces that we put together here.

And so the agenda for this workshop, start with a summary of the levelized cost of generation results, overview of the cost of generation model and its latest modifications, review of the cost drivers for renewables, integrated gasification, combined cycle, nuclear generation technologies, and preliminary characterization of building and community scale renewable technology costs.

Finally, there are several questions that we would appreciate feedback from the participants here, at the workshop, and those in WebEx, and those also who might listen in and then choose to comment later on, during the comment period.

We'd like the workshop participants to consider the questions; how might the cost of generation effort be revised to make it more useful? It's important to us that what we do serves -- serves the consumers of this report in useful ways.

Do the technology of levelized costs appear to be reasonable and, if not, why not?

And are the tax and tax credit assumptions reasonable? And these assumptions actually are one of the key changes that were made this year to the Levelized Cost of Generation Report and our -- our subject matter experts will be getting into that in far more detail.

And so for the next steps we're going to modify renewables, the integrated gasification, and nuclear generation levelized costs based on today's workshop comments and compelling information. We're going to post the staff model and users' guide. And the final staff report should be posted in September of this year.

And so with that, I believe I am done.

MS. GREEN: Our next speaker is Richard McCann, from Aspen Environmental Group.

MR. MC CANN: Good morning, I'm Dr. Richard McCann, with Aspen Environmental Group. And I'm actually standing in, in part, for Joel Kline, who is the staff project manager, who has contributed at least as much as I have to this whole process. But he's singing in the Alps today, is that right, in Austria, so he's not available to bestow his wisdom on us.

COMMISSIONER BOYD: Singing in the Alps or singing because he’s in the Alps.

MR. MC CANN: Well, Joel sent us an e-mail yesterday from Austria, that we couldn’t believe it, so I think he’s just singing there because he has to be there.

So I’m going to talk about the structure of the model in a very -- at a high level because the alternative is to spend two hours talking to you about the details of the model, so I’m going to try to do this fairly quickly. And then I’m going to talk about the changes in the model that we’ve made, and some of the implications of that.

And I’m going to start, first off, with discussing a definition of levelized costs, because that’s really the core output of the model. And I’m not sure that everybody always understands what we’re talking about, when we talked about levelized costs.

Levelized costs, basically, is a way of converting unequal annual costs to a constant cost term, a value that you can compare, a single value that you can compare between different technologies.

And you begin by finding the present value of the annual, the stream of annual costs over time and then converting that into a single present value amount using, in this case using a couple of Excel spreadsheet model functions.

This conversion process is exactly the same on that you use when you're calculating your mortgage payment on your home. So that's when you are paying that monthly payment, this is exactly the same process.

And so what it does is it allows you to have a single value to compare resource costs, as long as you understand all of the assumptions that go into those resource costs, and we're going to talk about some of those assumptions further on here.

And so one of the things about it, though, is that to understand that the levelized cost comparisons are only an approximate comparison, there's a lot of other things that go into having to do analyses with these costs in order to get really true comparisons. And in fact, what you really need to do is move to system modeling, that these costs are simply an input into a larger modeling effort. You can't just take these costs, simply, and compare them to each other and say, ah-ha, this technology's less costly than the other, that's not really appropriate to do with these results, but they're useful guides.

So what I'm going to do is just walk through a couple of examples. And that Power Point came up kind of strange, didn't it?

So on the left-hand side we have the cost per megawatt hour of different technologies, and those values range from 80 to 140 dollars a megawatt hour, these are just example technologies.

And you can see how the costs escalate over time between the two different technologies. The technology A, which is in red, starts at a lower cost but escalates more rapidly over time and technology B escalates at a slower rate, even though it has a lower -- a higher initial cost.

And we would like to know, simply, over this 20-year time period how do these two technology costs actually compare to each other.

And so the first step is to go through and develop the levelized costs and so what we do is we take technology A, and we take that value that is escalating and convert it into a constant annual payment and, in this case, it’s around $103 a megawatt hour.

And we do the same for technology B and we can compare technology A to technology B.

And in this case, where we have this particular set of assumptions, we find that technology B is higher cost that technology A over a 20-year time period.

Now, there are important -- you can make different assumptions that could change this ranking and it’s important to understand what those underlying assumptions are, and in our model we’ve tried to be as transparent as possible, putting those assumptions up front on the input/output page, and so that you’re able to see the key assumptions in the model.

Moving on to the overview of the model structure, this particular chart shows the complexity of the model, but also shows, we hope, the transparency of the model.

We start on the left-hand side with the inputs. There's the plant characteristics, these are the physical characteristics of the plant, a number of different elements that go into that particular cost, into the description of the particular plant.

There's the plant cost data and all of that is information that is the dollars and cents that result from the model come from that plant cost data.

We have the financial assumptions and they vary by ownership type, whether they're merchant, POU, or IOU, publicly owned or investor owned utilities, and the amount of debt in equity shares, the cost, the terms of that debt.

And then we have more general assumptions about insurance, O&M, various labor escalation cost rates and then, finally, the fuel forecast.

And then we also have the tax information that goes into the model. It terms out that how the taxes are treated in the model are very important when you are looking at the ranges, and Al's going to talk about this some more. What we assume about taxes has a very big influence on the final results.

Looking on the right-hand side, where we have the outputs, the important outputs are the one in the middle, which is the total levelized costs, that's the one that you probably have most interest in.

And then Ivin talked about the screening curves and the sensitivity curves, which are ways of measuring how the model results change based on different assumptions.

And we've also incorporated having high and low cost balance in the model for the first time, which we believe is a very important step and a result, and something that should be incorporated in future analyses.

We also went through a data gathering process. We're going to have a presentation this afternoon. Actually, I think that Gerry Braun's going to talk about this, initially, and then there's going to be more discussion later on about the data for the renewables, nuclear, and coal plants that are included in that. Those results can from the PIER group. That particular report is online, along with the staff draft of this report.

And those results were developed in a way that could be comparable with the results for the gas-fired generation.

We built the gas-fired generation data based on the survey results that we did in 2007, where we surveyed over 40 plants statewide. We believe that this particular study is probably the most authoritative study on generation plant cost data in the country, because no other analysis that we’ve come across has surveyed so many actual plants in terms of their actual costs, both construction and operating costs.

And then we’ve updated that both for construction inflation and also for comparisons with other entities that also do similar kinds of studies.

And so I want to talk about the changes in the model that we’ve had since the 2007 IEPR, and as both Commissioners pointed out, that we have responded to several requests, including incorporating ranges of changes and trends in costs over time.

Trends are particularly important for looking at the renewables because many of them have -- expect to have declining costs because of various factors, like learning by doing and economies of scale.

So we have trends that go up from 2009 to 2028. We’ve also separated out what we call transmission transaction costs that are the costs of transmission getting from the first point of interconnection to the load center, so that we clearly identify what the transmission, the full range of transmission interconnection costs are, what they are in the model, and those assumptions can be varied in the model quite easily.

We also changed the way we did the accounting for merchant-owned levelized costs, because we explored it some more with various models and found that we could come up with a better modeling technique than what we had used before.

We've updated the tax information and the various incentives, especially since the Federal law changed substantially, both in the fall of 2008 and again in February of 2009.

And then we also have looked at the question of tax accounting issues, because the financial meltdown in the fall changed the way that tax credits are now incorporated into the financing process.

So I'm going to talk about a couple of these changes, not all of them, but the most important one, the first one is the comparison of accounting methods.

We have two methods in the model, one is a revenue requirements method, which is essentially the way that utilities do rate making; and the second is doing a cash flow type modeling, which mimics the way that investors in merchant plants look at how they are going to cover their costs for their power plants.

One of the interesting things we've found is that the revenue requirements methodology implied a much higher levelized costs for merchant power plants than using the cash flow method, and we were surprised at the difference in the results.

The revenue requirements method, in this case the equity payments -- this is return on -- return of equity and return on equity, and the payments decreased uniformly over time. The revenues will change, fluctuate over time, depending on what the specified revenue requirements are for each one of the individual power plants, and this is basically the way utility rate making works.

In the case of cash flow modeling, it’s the market price that drives the model. So what you’re doing is trying to solve for a market price that, in the case we were looking at, long-term power prices, and so we assumed a relatively constant revenue stream that increased at a specified escalation rate, and that escalation rate is described in the model about how that occurs.

And there’s -- there are different ways of doing the revenue requirements assessment for merchant power plants, but it’s important to understand that there is this very different type of approach between the two different types of models. The utility base being it’s really cost-based and that’s converted into revenue requirements, and the other one being it’s price-based and now you got to figure out how you cover your expenses based on having that revenue stream.

In both cases the debt and operating expenses are the same between the two types of modeling. The debt terms vary between ownership type and that's specified in the model.

But the revenue taxes and equity payments are different between the two different ownership types and two different modeling structures.

So this compares the revenue requirements, the revenue streams, between the two different types of modeling for the merchant power plants.

Now, this particular graphic is not actually used in the model, but we produced it just for comparison purposes. This would be what the revenue streams would be for a merchant-owned power plant under revenue requirement modeling, and you can see there's these large, in some cases very large tax credits that are delivered to the merchants, operators in the first initial year of operations, and then the revenue streams can vary significantly over the time period.

Whereas in the case of the cash flow account -- oh, I just want to note that the scale on the left-hand side is not identical, not the same between these two graphics, so you can't make a direct comparison.

But in this case you can see that the revenue stream is relatively constant over time because these are specified in the contract terms ahead of time.

And then we looked at transmission costs. We have the interconnection cost, that is the connection to the first point of interconnection into the transmission system, and these costs are rolled into the capital costs.

In the case of the gas-fired power plants, they're actually rolled into the total linear costs which includes, for example, sewer, and water line, and natural gas supply lines into the power plant.

And then we have transmission transaction costs and these are the costs from the point of -- the first point of interconnection, which is usually the closest substation, out to the load center.

And the way we estimate those costs was through a combination of the ISO tariffs for those costs and additional transmission investment costs that were estimated in the 2007 IEPR scenarios analysis, and those costs vary by technology and by region.

So the other updates that we made in the model, in terms of assumptions, is we updated the renewable and alternative technology costs, and those are going to be discussed more in this workshop. They were also discussed extensively at the April 16th workshop, and so that information has been covered in the past.

We also updated the gas-fired technology costs, as

I discussed, updating the survey results and looking at other models.

We incorporated ranges for gas price forecasts, and I'll talk a little bit about that.

And then we updated and differentiated the financing assumptions that were in the model. We included ranges of financing costs; we were much more detailed in looking at a cost for the different ownership types, particularly for merchant power plants.

And one of the things is that for the merchant owners there's, of course, a lot of uncertainty about their financing costs due to the financial situation that really erupted last summer, in 2008, and has not yet settled.

And so to the extent one of the interesting things that we would like to know is are our financing assumptions for merchant owners really up to date and accurate, and we would like a substantial amount of input on that particular issue.

Talking about the range of gas forecasts, we came up with a methodology of estimating a range of potential gas forecast and it's based on looking at what the error rate was in past forecasts.

So for example -- for example, what we looked at was what was the EIA forecast in 1990 for gas prices and then compared to what actually happened compared to that forecast.

And so these bounding lines, the high average and the lower average are essentially how -- measure how far off the forecasters were in the past and assume, well, they should probably be about as far off into the future as they were in the past. And so that’s how we came up with a bounding range on the gas price forecast.

That average forecast is based on the 2007? -- the 2007 IEPR gas price forecast.

And then you can see, compare to other single point forecasts that have been used in other forums, the E-3 forecast being the -- in the various PUC proceedings, the gas utilities forecast that was put together in the green line, and then the 2008 Energy Information Administration forecast that was done last December, and you can see how all of those forecasts go forward in comparison.

And then finally we looked at the increases in capital costs for the different gas-fired technologies and you can see the increases in costs. Most of the increases in these costs are due to construction inflation. There was substantial increases in construction costs from about 2003 onto 2008.

This is using the data that we have to this point; it’s a little unclear as to how construction costs will change over the next several years because of the very large change in the economy. But that’s what we’ve got in the model right now between the two cases.

And with that, I conclude, and Al Alvarado’s going to come up and discuss the model results and the implications of those model results, with you.

Oh, Gerry. Excuse me, Gerry Braun’s going to come up and talk about the renewables cost drivers.

MR. BRAUN: Good morning, Commissioners and Advisors.

What I’d like to do, briefly, is talk about the progress we’ve made this year in providing good data for the analysis that Richard described, and a little bit on additional progress that’s going to be needed going forward.

Before I do that, I’d like to acknowledge a couple of contributions that really made all of the whole team contribution possible. John Henschon (phonetic) managed the PIER-funded project and Valerie Nibler managed it on the KEMA side, and their efforts really were exemplary, and I think credit’s due to them for much of the progress that we were able to make this year.

I want to go back very briefly to the April workshop, that Commissioner Byron mentioned, and we talked about cost drivers in that workshop and we had some recommendations at that time, and I’d like to just briefly summarize those, and then focus on trying to get our minds around what do we mean by cost drivers, what are the major categories, and what progress did we make this year, and some questions that came out of the overall effort.

In April, we basically pointed to the need to look across the whole menu of renewable energy options. There's basically a five order of magnitude scale difference from the largest utility scale plants to the systems that are deployed on buildings.

And we have a lot of experience at utility scale; we have growing experience at the building scale with the California Solar Initiative.

We don't have -- technology-by-technology we have some experience at the community scale, but don't have integrated renewable or integrated generation systems at the community scale to any great extent.

The bottom line in talking about the data is, basically, enormous diversity and endless variation, and somehow boiling that down so that we can give a small set of assumptions for modeling purposes is really the challenge.

So KEMA was asked to improve our cost baselines for renewable technology and to help us think forward to how we would go beyond simply the costs indexed to undifferentiated kilowatt hours and think also in terms of the relationship of cost to value, and not just the cost of energy delivered to the buyer, but costs delivered to energy customers.

So our recommendations in April were to try to boil things down to what we think will be the major contributors in renewable technologies in the longer term, focus on them, and try to understand how the global market is shaping not just the costs, but the technology options available to us.

And then, also, start to give some attention to integrated energy system cost, recognizing that no renewable technology can do it all, as in the case in the past, we need a mix of new sources. We need to look at natural gas as an enabler, rather than an alternative to renewables, and we need to optimize the whole generation system.

This is my multiple moving targets chart. And the point is that there is diversity in several categories that needs to be accounted for. Resources vary within California; all of the renewable resources are of different qualities, depending on where you are in the State.

Technologies are diverse, emerging and mature technologies and the applications of the technology and the scale at which they are deployed. And this chart really is just -- you’ve seen it before, but it attempts to kind of convey the point that we need to get our arms around the matter of diversity.

And this diversity also affects -- it drives the diversity in how projects are financed, and Richard alluded to this in his talk, that when you get into the details the differences in renewable technologies and their attributes really create the need to design the financing model for a project differently in each case, and we need to begin to understand how that works.

We weren’t totally consistent in our definition of cost driver this year, and I don’t think it -- I thought it was probably okay. There are a couple of ways that you can define the term.

The one that I like is a factor that causes a change in the cost, and we’ll talk about that in -- as a major way of looking at how costs might evolve in the future.

But, obviously, the major parts of the cost build-up are also cost drivers.

In general, though, it’s experience that results in the ability to change costs, and competition basically drives the change based on experience. And there are several ways, things that experience can help with.

First, just different technologies in different ways, energy capture, energy conversion, the scale of the plant, the scale of the equipment, the scale of manufacturing, all of these hinge on experience.

For example, in geothermal, energy capture is probably -- you know, what's going on underground is really important, and experience allows us to do a better job of designing ways to capture the energy.

Biomass we talked about in April, we talked about biomass, forest residue tora faction, that's part of the conversion process.

Solar thermal plants have, you know, the scale -- they're still not at the full scale commercially that they want to be at, and getting to that scale is going to reduce costs.

Wind turbines have scaled up by a factor of a hundred over the last 20 years and that's had a big effect on costs.

And likewise, the photovoltaic factories, panel factories have scaled up by a factor of a hundred and that's had a big effect as well.

And these are all experience-driven innovation, as well as using enabling technologies, like high-temperature thermal storage, to change the value equation, it also changes the cost equation, and those two things have to be optimized together.

So what we -- what we recognized in trying to refine a menu of technologies to look at is that technologies that are not in commercial use, their costs are really a matter of speculation.

And so we basically tried to differentiate between where we had experience that could be used to come up with good, reliable costs, and where we didn't, and we selected technologies in each range of scale because the scale of the technologies also matters.

If you have the right choice of technology, but you don't do your cost estimation based on the scale that it's actually being used, you won't get the right answer.

And so our menu pared down because we were -- we were focusing on where we have experience. But we also added some options where there is experience, including solar thermal power that uses high-temperature storage, that's commercially in use; co-firing of coal plants with biomass; upgrading hydro electric plants to increase capacity; and higher quality wind resources than those that were assumed in 2007, because there are such high-quality resources available in California.

And then we kind of put into a separate category things that probably are going to come on stream, probably we will have the experience, but we don't yet, high concentration solar thermal plants, concentrating photovoltaics plants.

Offshore wind is now a commercial option. In some areas where the -- where you're not dealing with the kind of deep water deployment that we would have to do in

California, and designs for deep water deployment are being developed; wave energy, integrated gasification combined cycle with carbon capture, again, not commercial yet, but something that may come, and next-generation nuclear power plants.

So this is the menu. And as you can see, we looked at each item on the menu at a specific scale and in most cases we’re looking at current technologies, in some cases we’re looking at technologies where we don’t think we’ll have good data for the next ten years, but after that we may.

And there’s one item missing on this list, that probably is in the data starting in 2018 category. Bill Glasley, from our California Geothermal Energy Collaborative pointed out that the Federal government has set aside; recently, $400 million to address enhanced geothermal technologies that would essentially expand greatly the resources available for geothermal deployment.

We use, now, the resources where there’s both heat and fluid in the right geologic configuration.

The enhanced geothermal basically creates the geological configuration where there’s the heat, so that you can extract energy from that.

And that’s something that’s on the horizon and it probably should have been on this list, but at the time we weren't expecting what -- the new initiative from the government.

So these are a couple of -- just I wanted to show this chart to indicate that each menu option had a different set of cost drivers. In some cases they were mostly just the elements of cost that build up to the total and others there were a combination of things that influenced costs, and things that add up to the total cost.

And as Richard indicated, we were asked to not just come up with nominal costs, as in 2007, but high and low costs that are plausible, and in the same cost breakdown, and with the ability to project these costs forward for the next 20 years, and so this is just an example of how the data was categorized and presented.

One of the things that I think is very important, that KEMA was able to accomplish, was to create a spreadsheet model that would allow -- allow this goal of being able to develop a cost forecast or trajectories for each technology to be done in a credible way, rather than kind of just guessing.

And basically, the model relies on what are called progress ratios, which is the key parameter in creating experience curves. And so this is just an example of one case where we have progress ratios for the average cost and then we use the weighting of the cost breakdown in the -- in wind turbines to come up with a weighted average progress ratio for the low and high cases.

And I'm sorry, I don't mean to take us down into the weaves, but I think it's really important to be able to have -- to be able to change the assumptions and to translate that into changed forecasts, because we will be continually working with the assumptions and we need to be able to plug those new assumptions in to the same model we used in the past to forecast.

So this is basically just what was done, was to use the progress ratios to forecast how costs will change as the amount of install capacity changes from year to year.

I think you're all familiar with that formulation.

The important thing to note, I think, is that as you begin to look, as you look at things this way, with this kind of an understanding that experience is really driving things, it is the industries that are growing the fastest that will generate experience the fastest, and we need to keep that in mind.

Some of the biggest contributors are growing, you know, there's a lot of installed capacity and the growth is not rapid. In other cases, the industries are at their early stage and they're growing very rapidly. So we would expect to see faster progress in cost reduction for those with higher growth rates.

One of the things from 2007, that we realized, was that there were some areas where costs that were coming out of our efforts were not necessarily in sync with the pricing in the market. Solar photovoltaics was an example.

And we asked KEMA, in 2009, to try to get some reference to pricing benchmarks, and other benchmarks, and other types of analysis that would help us validate the costs that are coming out of our levelized cost analysis.

And I would say we were -- this is a work in progress. We have some references, but we weren't able to get direct pricing data for all of the technologies.

One of the things that I would mention here is that it's pretty clear that our cost ranges are large, but the average costs and the low costs are really the ones that we need to focus on because, quite frankly, in many cases, the high costs are not going to be paid. We need to understand what the competitive cost range is going forward.

And the last thing we did was to try to account for scale, and you'll hear more about that this afternoon. And I should point out that the first four tasks that KEMA did are included in the interim report that you have. The last two tasks, related to price cost reconciliation and building and community scale technologies are -- will be in the final report, which we may not convert into a document, but will be available to those interested.

And I want to comment a little bit, this was not our task, Peter and KEMA were not asked to deal with this, but it's almost impossible to escape looking at this, the fact that debt and equity costs, especially in the turbulent period of the last two or three years, have probably had a bigger effect on delivered energy costs and bus par costs than the changes in the costs of the plants.

And basically, the financial meltdown, the recession, the stimulus legislation, those things that Richard mentioned, are big factors.

And in determining the weighted average costs that apply, across the board, but they apply differently, they are affected differently for each technology.

I don't think we have a great understanding of that, yet, we need to understand it better, and that's kind of why I put the -- I put the little illustrations here askew because I was hoping to say something more about that, but I realized we just need to do more work in this area.

So in summary, we've made some progress. We've focused on those options where cost experience can inform us and inform our work. We've identified which other options we should be monitoring closely. We've done a better job in identifying the representative scale of the projects that we should be looking at.

We recognize that the menu of renewable

technologies is not just utility scale plants, but a whole size range from building to utility scale.

We have started the work of coming up with cost ranges based on specific technology cost build up.

We've used I think, for the first time, experience curves to actually forecast future costs.

We've added -- even though renewable energy heating and cooling is not a -- doesn't contribute to electricity production, it affects the amount of renewable electricity production required and we've started to address that.

And we've started to do a better job of putting our estimates in the context of others' cost studies and pricing benchmarks.

In the future we need better accuracy, especially for the high penetration renewable options, and at all deployment scales.

We need to start looking at the value side of the equation.

We need to -- we need a better understanding of the relationship between plant costs and costs of financing, we need to integrate our thinking a little bit more on that.

And we need a better handle on not the total cost range, but the competitive cost range for the renewable technology.

So a lot of work on cost forecasting, I won’t go into all of the things that need to be looked at, but there are several.

And lastly, I want to summarize kind of the questions that come to mind as you go through a project like this. Is there a need, you know, we’re doing these cost updates every two years, and if the last couple years are any indication, the shelf life of the results is probably not two years, should there be ongoing efforts to monitor not just the technology progress, but also the changes in costs?

Do we need to also monitor the changes and the shifts that are occurring in real time, and the cost of capital, that are changing, you know, basically changing decisions about deployment?

Do we need more work to validate our levelized cost results?

And, I mean, this is just something that occurred to me, it seems to me that the variability in the cost of natural gas-based options and renewable options ought to be, you know, either one’s more variable than the other or, it’s hard to believe that they’re both equally variable. We’re using one as a benchmark for the other.

I think we need to better understand the variability question and the question would be how do we do that?

Is it possible to expand or somehow include the issue of value in this kind of analysis, in an integrated way?

And how can we better secure the informed review of the active market participants in validating our work?

Thank you.

I think we didn’t ask, yet, if you have any questions but --

COMMISSIONER BOYD: A simple question on how you’re -- practically your last point here about variability, and your two comparisons. I was just wondering, even those costs of gas technology escalate, which you document here, is the variability with gas tied almost exclusively to the variability of the price of natural gas that we’ve all struggled with the last couple of years in trying to get a fix on -- trying to do accurate costs estimates.

Versus the other technology where, I guess, technology development costs are still swinging around, as well as costs associated with siting and what have you. I don’t know, am I way out in space somewhere or --

MR. BRAUN: I’ll just -- I’ll give you a simple answer to that. Renewable energy technologies are almost all, with the exception of biomass, capital intensive, and most of the total levelized cost is related to capital.

With natural gas it’s the other way around, most of it is related to the 20 or 30 years worth of fuel purchases that are required and it, of course, depends on what type of plant and so forth.

And that’s the reason for the question because once you build a renewable power plant, if you are building a plant with mature technology, you really should know pretty well what it’s going to cost, and there isn’t this big question mark in terms of what is the stream of costs that’s going to come in the future because you’ve paid up front.

Whereas, that’s not the case with a natural gas type plant.

Does that help?

COMMISSIONER BOYD: That helps. The fuel for some renewables is free.

MR. BRAUN: Yeah, it is. It is.

COMMISSIONER BYRON: Mr. Braun?

MR. BRAUN: Yes, sir?

COMMISSIONER BYRON: Maybe a couple of comments and questions, I’ll start with the questions.

As I was looking at your presentation, the table that you’ve used before -- let me start this way. We ask you to be an economist, and an engineer, and a private detective; right, and a lot of this is really trying to find the information that you need to do the analysis.

In fact, I note that your last slide -- oh, I think I'm looking at the next presentation.

Your last slide really concentrates a lot of the information around renewables that you don't have access to.

MR. BRAUN: Right.

COMMISSIONER BYRON: However, I note that this Commission has half a dozen cases before us, there's a lot of cost information that's out there but, yet, it's tied up in the procurement process through nondisclosure agreements. And, of course, it's highly competitive information that the utilities tell us that they need to keep to themselves to protect customers' costs.

But, of course, we'll see later on, when Mr. Alvarado gets into the results, the costs for the IOUs seem to be a little higher than the others.

Where I'm going with all this is that information is there and I'm just always perplexed why we don't make it more available, and how helpful it could be in making a more competitive marketplace; do you agree?

MR. BRAUN: I do agree. And certainly what's gotten my attention is the emerging debate, policy debate over, you know, the cost of the portfolio implementation, the cost of feed-in tariffs, the cost of whatever we decide to do to meet California's energy needs.

There are some huge investments involved and getting the best possible cost information is really important.

And as you say, Commissioner, the best information really is the information that is the hardest to get at. And I would like to believe that, you know, a more vigorous digging on our part would help but, probably, there are other things that would help as well, and I don't really have any specific suggestions.

COMMISSIONER BYRON: Well, I just look at the variability around your costs, for instance associated with solar photovoltaic, and they're extremely -- the range is extremely high. And maybe that's true and the bid information would reflect that and I personally don't know how that would hurt consumers, because the next bid would be even more competitive, I suspect.

Let me go back to early on when you were talking about -- well, yeah, let's talk about storage. Early on you talked about, you know, the high temperature storage and the value cost innovation around that. Have you thought about or have you begun to think about how to incorporate that in your cost of generation model?

MR. BRAUN: Yes, we did and, in fact, KEMA did generate two sets of costs for solar parabolic trough. One was with, I think it was six or eight hours of energy storage, which significantly, of course -- well, significantly increased the capacity factor in the case that we looked at. It also increased the cost a lot.

So the effect on levelized costs may not have been very big, but the effect on the value of the plant to, you know, a particular utility system or a particular electric system might be much different, might be much greater.

And that was kind of an example of this issue of getting at the value cost equation.

COMMISSIONER BYRON: Yeah, Commissioner Boyd, I know, came back from having looked at a number of -- or at least one facility that had the thermal storage associated with solar and maybe even has more information than you do around cost but, again, that was because it was probably more available.

I’ll open that up to you, Commissioner Boyd, for any --

COMMISSIONER BOYD: Well, I was just thinking, as you were speaking, before you made your comment about my experience that, yes, in Spain they have operating solar thermal with multi-cell storage. And for a 50 percent increase in the cost of the facility they’re running 18, 19 hours and claim they could go seven by 24, their contracts cut them off at 18 or 19 hours, which seemed like a very intriguing possibility for some parts of California that have got a lot of sun, but no natural gas in the neighborhood, so to speak.

But I assume you people can mine that kind of information, I don’t think I have anything that’s new.

MR. BRAUN: Well, KEMA did a good job of mining information on that this year. But it does raise a -- you know, it does raise some interesting policy questions because right now the market is structured, you know, to value that contribution of expanding the capacity factor if it reduces the cost of the kilowatt hour, but not necessarily if it increases the value of when the kilowatt hours are delivered. And that’s something that probably would be worth taking a look at.

COMMISSIONER BYRON: I’ll end with one thing, the table that you have back -- and your slides aren’t numbered, but early on the table that showed the primary applications and the second applications, we’re certainly beginning to see a lot more solar photovoltaic on a large utility scale.

MR. BRAUN: Yeah.

COMMISSIONER BYRON: I wonder if that’s really a secondary application anymore? It’s not proven, yet, but of course we’re seeing an awful lot of projects that are being proposed.

MR. BRAUN: That’s the -- that’s the hazard of using a chart that you put together a year or two ago.

COMMISSIONER BYRON: That's right, and you're always going to be playing catch up in this game.

MR. BRAUN: Yeah.

COMMISSIONER BYRON: My sense is, and I'll say this as well for my concluding remarks, that you've done a pretty good job of catching up on this cycle, but it's always going to be catch up with the cost of generation model.

Thank you, Mr. Braun.

COMMISSIONER BOYD: I'll make one comment to finish the rest of the story on renewables in Spain and, by the way, it didn't cost the taxpayers anything to get me there. I was a guest, along with President Peevey, of the Spanish government.

They have a very generous feed-in tariff and they are accruing an incredible debt, government debt, they do not pass the cost on to consumers.

My friend, President Peevey, delighted in that factoid, so I think we know where he may stand on feed-in tariffs.

The flip side was he was as impressed, or maybe more impressed with the thermal storage and the cost factors related thereto. So I'd say it was productive in that area and he and I, frankly, talked to LADWP about their own slate capabilities and energy storage since there's no natural gas anywhere near Owens Lake that we could find.

So anyway, we'll see, costs will tell.

COMMISSIONER BYRON: Yeah, I think it speaks well for potential technologies, and they're not always developed here first or applied here first.

Mr. Alvarado.

MR. ALVARADO: Good morning, my name's Al Alvarado, I'm with the Electricity Analysis Office here, at the Energy Commission.

You will see Joel Klein's name up on this set of slides. As Dr. McCann noted, he is actually the master mind for most of this project and, actually, these are his slides that he prepared in anticipation of giving this overview at an earlier date for the workshop.

Knowing Joel, he's probably in an internet café in Vienna, you know, listening in on WebEx to make sure that I actually do a decent job in presenting his work.

COMMISSIONER BOYD: You mean he would come down from the Alps for this opportunity?

MR. ALVARADO: Actually, knowing Joel, he probably would.

COMMISSIONER BYRON: And that is an interesting thought, isn't it, that your words are being heard, possibly, around the world.

COMMISSIONER BOYD: In a pastry shop in Vienna, in an internet café.

MR. ALVARADO: Or with a glass of Pilsner.

COMMISSIONER BOYD: Ah, it is late, isn't it?

MR. ALVARADO: So is the -- were the element that Dr. McCann presented, and what Gerry had provided, and the contributions of the larger team all come together.

What I'm going to do here is just sort of hit the highlights of the results of integrating all of the inputs, the modifications to the tool, and this is where we come up with the estimates of levelized costs for each of the generation technologies.

The details are found in both the staff report and most of the more detailed documentation of the input assumptions are also found in the KEMA interim report.

What I'm going to do today is basically just hit the highlights of the key results. I also want to provide a comparison of the results that we did back for the 2007 IEPR.

Dr. McCann provided a snapshot of the tax treatment issues and, as you will see, it actually does have some interesting results in the levelized cost estimates.

And I think Ivin also provided a teaser in terms of -- it's actually more of a warning about how these model results, levelized cost results could be used for any sort of electricity resource planning activity.

The workshop questions are also presented at the very beginning and this is really intended to try to focus the type of feedback that we are actually seeking.

Depending on the feedback we get today, we will then evaluate to see if there’s a need to modify any of our assumptions, re-calculations, and in our preparation for the final report, which we expect to release towards the end of September.

In summary, the cost of generation results, what I mean by traditional levelized cost reporting is that, like in the last report we did provide a single point levelized cost estimate, so as a starting point here we do have a single point comparison.

But given the guidance and directions we received from the 2007 IEPR Committee, we engaged in further efforts to identify trends, not only where the instant costs are today, but where we might expect the instant costs might be in the future, which are the prime drivers for calculating the levelized costs.

More significant in this analysis, too, is we’ve come up with not just one single point of levelized cost estimate; we’ve come up with a range of both high and low estimates. And you’ll see with some of these slides that the range is pretty wide through some of the technologies.

And just for a quick comparison, I think the latest report that I've seen, that actually used some levelized cost estimates is the report that was done through the PUC on the 33 percent renewable study.

I've just got one slide to show a comparison of the levelized costs they included in that study.

These are the levelized cost components but I think the slide that Dr. McCann has, that shows most of the inputs and the outputs probably provide a little bit more greater detail, but this just sort of hits the highlights on what's included in the fixed costs, the variable costs, and the modification that we did this time around has come up with transmission cost components.

So this is our single point cost estimate. I call this average because this is where the averages of all the different input variables are applied to come up with the single point cost estimates here.

And I'm sure it's kind of difficult to really read the slides, and I think the black and white prints might make it even more difficult for folks, looking at this, in the audience.

The main story to take out of this is a comparison with not just the levelized cost estimates between different technologies, but what would be the levelized cost if the developer was either a merchant, an investor-owned utility, or a publicly-owned utility?

You find that for some of the technologies the merchant -- the levelized cost for a merchant developer would be significantly higher than an investor-owned utility, or a POU, and part of that's due to the financial cost assumption inputs that a merchant would encounter compared to a utility.

COMMISSIONER BYRON: Mr. Alvarado, forgive me for interrupting. There's quite a spread here between the merchants and the POUs. Are we usually essentially the same operating assumptions for all of these peakers? I'm sorry, I'm concentrating on the top three, the peakers.

MR. ALVARADO: Right, we're using the -- the assumption characteristics of the peaker would apply to each of the developers, whether it's a merchant, an IOU, or a POU.

What really makes the difference there is going to be the financial assumption. A municipal utility will not have the tax burden that a merchant would have.

However, on the other hand, a merchant, if you look down at some of the renewable technologies, will have different tax incentives, and that's why you'll see some of the shift between some technologies where a merchant, if a merchant is going to develop a gas-fired plant, it might be relatively expensive.

But if you look at some of the renewable technologies, their overall cost might be lower.

And with the help of my friends, since these are the folks that really contribute the details, Dr. McCann?

MR. MC CANN: Well, at this moment I'm channeling Joel.

To answer your specific question about the combined cycle plants, the --

COMMISSIONER BYRON: No, actually, the simple cycle plants is what I'm talking about.

MR. MC CANN: Right, excuse me, simple cycle, wrong word.

The simple cycle plant assumptions are different, the operating -- the capacity factors. It's a ten percent capacity factor for the POUs, because that's what we found historically.

But for the merchant operating plants it's five percent. So that is, as you noted, there's this big range.

And in that one particular case the capacity factors are substantially different between the two. There's actually some difference in the combined cycle as well, but it's much smaller.

COMMISSIONER BYRON: Yeah, that would account for most of that difference?

MR. MC CANN: Correct.

COMMISSIONER BYRON: Thank you.

MR. ALVARADO: Thank you, Richard. Please do come up if I, you know, characterize Joel's work adequately.

So to move on. So the next step in the project is to try to come up with a trend of not just what it's going to cost to develop any of these projects today, but what would it cost to develop these projects into the future?

And in this case we try to look at the development of cost, this slide shows the instant cost trends from 2009 going through 2028.

I think what is notable here is that many of the technologies don't really vary significantly in their instant costs, except for a few, and the noted changes are like for the, let's see, solar photovoltaic plants that do sort of cut through all of these other trend lines.

In this chart we have instant cost trends for the emerging technologies, and these do start in 2018. And as Gerry Braun pointed out, you know, these are the plants that we had a really difficult time in really trying to come up with good estimates, but I think this is the best shot in coming up with the instant cost for these emerging technologies.

Nuclear, at least the one nuclear technology does trend higher in the later years, whereas offshore wind and ocean wave -- offshore wind actually climbs and ocean wave tends to be pretty much level throughout the years.

In this slide, this is the -- now, this is the result of the tool, where we come up with the levelized cost. And again, this is just the average cost, the single point forecast of the average cost.

In the later slides you'll see the trend in the actual range of the calculated cost.

Not much to really say here, other than to illustrate that the simple cycle plants, type of generation technologies are much higher, and you'll find some -- the line down below is pretty compressed, it comprises the coal IGCC plants, and some of the advanced combined cycle plants.

This is where the tax implications actually gets manifested. So these are the levelized, average levelized costs for the renewable technologies and you'll see that there is sort of this declining trend for some of the technologies and a quick bump up around 2015.

And I think this is really -- I think the effort that Dr. McCann was trying to point out, that the -- and what Gerry's pointing out, that current tax structure really does make a significant difference.

I think the open question is what is going to happen once we get to this point where the current tax structure terminates, and whether there's an expectation of whether these trends will either continue or some of these developers are really going to have to take a larger burden on the development costs?

The same goes for the baseload technologies. You do see this bump up in the levelized cost estimates and these baseload technologies are renewable, so renewable technology, so they do encounter the bump up in the tax changes.

And we broke these charts up because, really, there’s so many technologies and we just have one big jungle set of technologies. But again, this is demonstrating that the trend, again, the technologies with the tax implications.

This is the -- in this slide we show the -- now the range of levelized costs, and you will see the red line that cuts through each of these bars is the average estimates, which is represented in earlier charts. But you’ll note in each of these blue bars that the actual range could be much larger than in comparison from one levelized cost, from one technology to the other.

And in some parts, when you’re dealing with the simple cycle plants, or any of the combined cycle plants, the main variables are going to be the fuel costs or even the capacity factor. If the plant is operating at a sub optimal capacity factor, it really is going to have a significant impact on the levelized costs estimates.

Actually, this probably gives you a better view of not just the ranges, but where the actual numbers sort of fall within the ranges.

Some of the technologies, like the hydro small scale, is really, I understand, because these technologies, themselves, the characterizations, there is a wide range in how these plants could be configured to operate.

And this chart shows the range of the levelized cost on -- when we're looking out at 2018 to see how much they could really vary also in the future.

In this chart, this is where now we include the emerging technologies, the nuclear plants, and some of the other sort of; I guess the wind, the cost for wind, right.

COMMISSIONER BYRON: Just so we're reading that figure and the previous figure, in looking back at 14, some of these go off scale; correct?

MR. ALVARADO: That's right.

COMMISSIONER BYRON: Okay.

MR. ALVARADO: The first one, at least for the 2009, was the full scale.

In this one we're trying to at least blow it up a little bit more so you can actually see the main differences and include the actual levelized costs.

COMMISSIONER BYRON: Right, but the simple cycles off to the right there go off scale?

MR. ALVARADO: Yes, they do.

COMMISSIONER BYRON: Okay.

MR. ALVARADO: Now, just for a general comparison to another report, in this slide, the only reason we brought out the PUC report is that that is the most recent one that was used to evaluate the potential cost implications of varying levels of renewable development penetrations.

And my understanding that the basis for the costs that the PUC used were estimates that E-3, their consultant, actually used the RETI numbers, and updated some of the RETI cross-curve estimates to come up to more current developments in the financial markets.

And I just want to note that the RETI estimates are actually based on the inputs that were derived from the 2007 IEPR, so we're just sort of making a little bit of a circle.

COMMISSIONER BYRON: Of course, I believe you, but let me ask a question. I mean, maybe -- I mean, they're in range; correct? Yeah, they're all within range. No, not quite, some of them are a little low.

When I say within range, the values on the right curve seem to be within the span of values that you have on the left side, except for maybe one.

But is that indeed what they said in the report, that they based it upon our cost of generation model from the '07?

MR. ALVARADO: Well, E-3 references RETI and the consultant for RETI came up with their own cost estimates and they used the input assumptions that we -- that we developed for the 2007 IEPR. They've applied their own levelized cost of generation model using much of our inputs, and with some changes.

COMMISSIONER BYRON: Uh-hum.

MR. ALVARADO: So we're all sort of working a lot from the same base.

COMMISSIONER BYRON: But I think you're implying they're behind.

MR. ALVARADO: Well --

COMMISSIONER BYRON: They're using an older model.

MR. ALVARADO: They're using their own tool.

COMMISSIONER BYRON: No, I like their results better because it's narrower.

(Laughter.)

COMMISSIONER BYRON: Right, and it looks like it's more accurate.

MR. MC CANN: Precise.

COMMISSIONER BYRON: Precise, thank you.

MR. ALVARADO: By appearances, right. And this is really the purpose of presenting this slide is that if you really want to do a integrated resource planning exercise to evaluate your resource options, given all the different variables, there really is a much wider range in what it may cost to develop these projects than some of the simple point estimates and the small ranges that we've seen in other studies.

COMMISSIONER BYRON: But as Mr. Braun indicated, as well, we can assume that a number of the higher case -- the higher cost projects won't enter into contract because they're pricing will be out of range in a competitive bid situation.

MR. ALVARADO: That would likely be the case. And our effort here was to at least investigate and look at all the different technologies and see where they would -- they could fall out.

COMMISSIONER BYRON: Uh-hum. Well, I think what I'm hinting at is, of course, the Public Utilities Commission has access to all the procurement information around renewable energy, and I just wonder if this is a better representation of investor-owned utility costs for renewables?

But I don't know that you could answer that.

COMMISSIONER BOYD: They used RETI.

COMMISSIONER BYRON: Well, yes, they said they used RETI results but, of course --

COMMISSIONER BOYD: It comes back to us.

COMMISSIONER BYRON: -- which stakeholder representation there would include a lot of the vendors, and suppliers, and developers in the wind and the photovoltaic area, so that might also cause a narrowing of costs here as well. Maybe, they would tend to put their best foot forward, as well.

MR. ALVARADO: I would assume so. At least with our effort here we are -- there's been a numbing amount of work that's occurred in these last six months and at least our effort here is to document all of our different assumptions.

And part of the purpose of this workshop is if we're really off base on any of these different variables and the results, we would like to hear from the stakeholders. And we will make modifications if deemed necessary.

COMMISSIONER BOYD: I like our lower ends better. But our upper ends are -- so talk about variability.

MR. ALVARADO: So the next step here is I just want to give comparison of what we did to the 2007 IEPR, a look at, now, just the levelized costs. We compare some of the key variables and show how the tax benefits also make a difference.

In this slide we have comparison of the 2007 IEPR, which is the green bar, and the most current estimates.

So in some cases we'll find that some technologies are somewhat -- are slightly lower or, in some cases, even significantly lower than the estimates we did in 2007. And part of what drives some of these costs differences is not only the instant costs may have changed, but we've -- I think this is also in part due to the financial assumptions and the tax treatment, not only using the revenue-based model, but also the cash flow model that provides us a different set of results.

And for the 2007 IEPR we did not do a forward looking case to try to evaluate what would be the trend in development costs for technologies in outer years.

But what we did over here was we used the 2007 baseline assumptions for 2007 and escalated moving it out to 2018, so we can at least have a line-by-line comparison.

And as you'll see for some technologies, very few of the technologies here, that the current estimates are a little bit higher, the levelized cost estimates are higher. But for some technologies, we're significantly lower than the estimates we developed two years ago.

COMMISSIONER BYRON: So I'm just trying to understand if we have an apples-to-apples comparison then here. You have to assume an annual escalation percentage, is that going to be the -- is it the same or similar for the '08 IEPR?

MR. ALVARADO: Richard, do you have any basis for this?

MR. MC CANN: Yeah. When you say -- I'm a little confused because you said the '08 IEPR, so I'm not quite sure.

COMMISSIONER BYRON: If I understood, Mr. Alvarado, the '07 didn't have an out year prediction, so you escalated the '07 IEPR prediction out to 2018?

MR. MC CANN: Right. And so there was a comparison in '07 of future years, but we didn't have good trend data, particularly on renewable technologies, how those costs -- how we might have experience curves, which is one of the innovations that was added into this model.

So the 2018 values for the '07 don't include that kind of change in the trends of the costs, it was just simple inflation escalation out for those costs, out into the future.

And so that's the comparison that was done here, in looking at 2018, was the '07 assumptions just escalated out, which is the model had the capability to do that in the '07, it just didn't have the other information about the trends in future technology costs.

COMMISSIONER BYRON: And but -- a further question, neither really include that enormously high construction escalation we've seen in the last couple of years, either, have they -- do they?

MR. MC CANN: For the ’07 case, that’s right. And so that’s why, for example, when you look at the ’07 versus the ’09 and you see that the ’09 is generally higher costs, that’s because of the unforeseen construction cost escalation that occurred between -- that we had not fully captured in 2007 and really ballooned up in 2008 and -- 2007 and 2008.

COMMISSIONER BYRON: Okay, thank you.

MR. ALVARADO: So this brings us to the tax treatment issues and a large part of the changing, the levelized cost estimate really is due to the tax treatment, as Dr. McCann had pointed out. And I think this is actually a significant uncertainty when we start looking out on the future years.

Do we assume that when the tax rules actually terminate, whether it really is going to just drop dead at that point and developers will encounter different tax treatments or are we going to assume maybe the possibility that a similar treatment is carried forward in those outer years?

This slide does show what would be the tax benefit, looking at the average levelized cost case, and you’ll see that some technologies that -- with and the -- where you have the extended red bar is without the tax benefit. So for some of the technologies you will see that the tax treatment is very significant when you come up with the levelized cost estimates, particularly for some renewable technologies.

We did this comparison for both the high and low case. You'll see that the tax implications in the high case is much smaller than what we found in the average case. And in the low levelized cost estimates, the tax benefits actually is a much more significant role in deriving these estimates.

So since we are trying to come up with a range of levelized cost, all this slide here does is sort of shows what the actual combined range of the tax benefits and without tax benefits, and how that contributes to our range of levelized cost calculations. Since the bottom bar really captures both the estimates using the -- with the tax variation.

So like with solar photovoltaics, you'll see that the tax benefits on the low end versus the higher end, without the tax benefits, is what comprises, in part, our range of localized costs for that particular technology.

This is basically the same slide that Ivin had earlier, and the only point we wanted to make is that when you used levelized cost this is really only one attribute that is used for integrated resource planning analysis.

We’ve used these levelized cost estimates to come up with screening curves for general comparisons of one technology to the next, but the next level, if you want to really engage in a full evaluation of the implications of these different technologies, you would have to consider how a plan may operate, capacity factor many times really does make a big difference on levelized cost estimates, and it is -- we really need to take the whole picture in mind when we’re doing any kind of resource planning analysis, because levelized cost is a significant input, but not everything when making a simple comparison.

Another point is that the location, actually, will make also a big difference, and when you try to understand the potential levelized cost, in part, because of the interconnection cost association.

And the other element, I think this was pretty much what Gerry was pointing out, that these costs do not really equal the market prices and we do get calls at times from folks, for this information, assuming that it really is the same thing.

And another element is these costs at this point do not include any other system modifications like -- or externalities, such as the emission effects.

Those kind of studies only would require, really, a system simulation evaluation to determine those kind of implications.

So with that, that brings us back to the list of questions that --

COMMISSIONER BYRON: Before you go to the questions let me just check here, Commissioner Boyd, do you have any more questions for Mr. Alvarado?

COMMISSIONER BOYD: Not really questions. I guess a question of myself, on this whole process, what struck me last night in reading all this, and it has been driven home today continuously, is the high and getting higher cost of simple-cycle machines, and the fact that we, you and I, and others have a lot of siting cases involving very large simple-cycle machines, which have always bothered me anyway because of the inefficient use of gas.

But anyway, the cost -- the cost factor, which is a product of the very low utilization you referenced, is still troubling me a lot and is something I want to get out of this whole process.

So not a question, an observation, before we get to the real question.

COMMISSIONER BYRON: And I think it’s a good one. You know, you’ve got to bury a lot of cost over a few hours’ operation with simple cycle. And, of course, it’s the dispatchability of that machine that gives everybody a lot of comfort. But maybe we’ll get to the point with photovoltaics and storage where there’s the similar level of comfort and the cost, I think, will certainly begin to compete based upon the numbers we see here.

I was struck, as you were giving your presentation, in addition to asking you to be economists, engineers, detectives, we also need you to be accountants in doing this analysis.

And as you were going through the tax treatment issues, and I’m not going to ask you any specific question about tax treatment, because I’m not very comfortable at all with all that stuff, but have we gotten some confirmation from the developers or the merchants that we have -- we have the treatment, the tax treatment correct in the modeling?

So it’s really a process question, are we getting feedback, have we verified or checked, are we looking for that kind of verification as a result of this workshop.

MR. ALVARADO: Well, and I think, again, this is part of the point of this -- the purpose of this workshop is to receive this kind of feedback.

We have had some calls from individuals, asking if they’ve adequately interpreted some of the tax assumptions. So at least we’re having some dialogue with some of the developers.

I will defer to the folks that actually, really did most of the research and took on this task of really trying to understand taxes and tax codes for each of these plants, for these kind of details.

Anything to add, Richard, to that effect?

COMMISSIONER BYRON: All right, well, we’re certainly interested in that because -- and again, it’s probably more a measure of my uncertainty around this, how this is dealt with in the cost of generation, but I am looking for a verification that we’ve indeed, as State employees who don’t compete in the marketplace out there to try and build generation, that we understand how their modeling it and how they -- how they take advantage of tax opportunities.

I just want to make sure we’ve got that right. For instance, as I recall, part of this stimulation package that was passed last September, at the Federal level, the investor-owned utilities stuck an issue in there that they now get a favorable tax treatment on renewables, they get investment tax credit associated with renewables that I believe they did not have before.

So let me ask, is that, for instance, incorporated in this model?

MR. MC CANN: Looking at the tax provision and maybe the utility representatives can clarify this; it appears that they have to make third-party sales in order to get that, to be able to claim that credit. So, essentially, they can’t claim it even though it’s in there. They have to sell to another utility or another load-serving entity in order to claim the credit, from our reading of the provision. But that might be that if the utilities have more information about that, then we would change the assumption in the model.

And the thing about this model is that it’s very easy to change that assumption and generate a new set of results.

COMMISSIONER BYRON: Well, that’s one we’re certainly interested in because it’s not as though the model’s going to change the world, but that provision may in fact change utility-owned generation with regard to renewables going forward.

I was talking to a utility executive recently and asked him, where are those projects, certainly expected to begin seeing them?

And his response was, you will, it just takes a while to put these deals together.

So I know that they’re out there looking and I want to be sure that we’ve properly captured that tax treatment when we do these kinds of cost models so we can understand the comparative costs between the merchants and the investors.

MR. MC CANN: Yeah.

COMMISSIONER BYRON: It’s not criticism at all; I just want to make sure that we’re including it.

MR. MC CANN: Right, and those -- that -- those are exactly the kind of questions that we want to answer in this tax treatment, because the tax law is unclear in some cases, and the IRS is not always given clear interpretation of treatment of various tax issues.

And also, with the changes not only in September, but also in February, of the tax treatment, that those things changed the situation substantially.

And then along with that, as if there was a market for selling -- essentially selling excess tax credits, that Lehman Brothers was the core player in that and they disappeared.

And so all of that disappeared in the February 2009 era, allowed full claiming of tax losses. That provision only goes until, I believe, 2012 or 2013, which is why you see those jumps in the costs.

And actually, this is a question for you to make, as policy makers, is what sort of assumptions do you want to use in your planning process about what Congress is going to do about tax laws between now and 2017, when many of these provisions expire.

COMMISSIONER BYRON: Okay. Well, Commissioner Boyd’s the expert on what Congress is going to do.

(Laughter.)

COMMISSIONER BYRON: All right, good. Well, we're certainly interested in that, for these reasons. So I think that's a great lead-in, Mr. Alvarado, to the questions. Are you going to lead this process with regard to you're seeking some public comment at this time?

MR. ALVARADO: Sure. Basically, I'd like to -- we can sort of phase this to anyone here today. If you have any comments, please come on up to the podium, comments or questions.

COMMISSIONER BYRON: Well, it's just that I interrupted you before you got to your questions and so I wanted to hand it back to you on how you wanted to handle it.

MR. ALVARADO: These are the main questions that we've identified earlier; I think this is the core of the type of feedback we're seeking, so I'm open to any feedback from the audience.

COMMISSIONER BYRON: And if you would, please introduce yourself for everyone.

MR. TONY BRAUN: Hello, my name is Tony Braun, I am Counsel to the California Municipal Utilities Association.

I just have a question and I think comes hard on to the questions that were just raised here and I, too, am not an accountant. The predominant --

COMMISSIONER BYRON: But we know you’re an attorney, Mr. Braun.

MR. TONY BRAUN: I am an attorney, so maybe I have some insight into some of this.

The predominant model that appears to be used by many of the CUMA members, when investing in renewable resources, is sort of a triangle model of private developer and ownership of facilities, which is utilized to take advantage of the tax credits that are available, an output sale of the contract, of the output of the project to a load-serving entity, which is the CMUA member, and then essentially a tax-exempt financing prepay for the output of that utility to take advantageous of the ability of the CMUA member to issue tax-exempt security.

So my question is when I saw those spreads for certain of the cost drivers, for some of the renewable technologies, I was just curious as to how much of that type of financing structure for projects was reflected in those graphs?

COMMISSIONER BYRON: Good.

MR. ALVARADO: Richard, I’m sorry, I’m going to have to defer to a lot of these details. If Joel was here, I think we’d be able to field most of these questions.

MR. MC CANN: Right. Yeah, between Al and I, we have some knowledge of Joel, so maybe we should be bound together and --

COMMISSIONER BYRON: Get him on the phone.

MR. MC CANN: Yes, yes, what time is it there?

But we did not do that type of -- incorporate that type of project financing. It was something that came up looking at particular reports, but that's the sort of comment, if CMUA can give a very detailed description of how that project financing works, we can attempt to work it into the model.

But general -- I got to be honest, general comments won't help us, they got to be very specific.

MR. TONY BRAUN: I'll see what we can do on that.

MR. MC CANN: That's.

COMMISSIONER BYRON: Well, thank you.

MR. ALVARADO: Please come up.

MR. BARMACK: Matt Barmack, from Calpine. Just on that last point, I know that some people at Lawrence Berkeley Lab, including Brian Wiser, have done a lot of work on sort of the project finance structures for renewables deals, and I'm just wondering whether you've tapped into any of that -- any of that work?

MR. MC CANN: We've looked at their reports and actually used a fair amount of information in doing that analysis.

The municipal co-financing model wasn't actually in any of the reports that I saw by them, but they might have one somewhere else.

MR. BARMACK: Okay, I had another question and then two comments. The question was really about the claim, Richard, that you made in your presentation about the radical, what I understood to be the radical divergence between the results you got from sort of a revenue requirements approach versus a cash flow approach, and maybe I'm misconstruing the claim, but is that driven by the modeling as opposed to the difference between your assumptions about merchant cost of capital versus IOU cost of capital?

MR. MC CANN: Yeah, it's in the modeling. We used all identical assumptions except for using the revenue requirement method versus the cash flow method.

MR. BARMACK: Okay, in that case, I guess, I find the result very surprising because, you know, there's sort of a lot more out there that shows the equivalence of the two approaches, at least for investment decisions, when you used comparable assumptions in both approaches.

So I'd be happy to send you some references, but I really encourage you to push on that a little bit more because I'm not sure that result is correct.

MR. MC CANN: Well, it's -- when we say up to 30 percent, that was just in a few cases. But it's really, the two things that drive it is the way the tax credits play out, and the other thing is that the discount rate impacts are different in the two different methods because of the -- it's different cash streams or, in some cases, there's actually different discount rates that are applied to different cash streams in the model, whether they're equity or debt components of the model.

MR. BARMACK: Yeah, so I guess, so you're going to release a version of the model?

MR. MC CANN: Yes, yes, there will be a version posted.

MR. BARMACK: Okay.

MR. MC CANN: And I'm not sure how it's going to be posted up there, but it would be available, it's in an Excel spreadsheet format.

MR. BARMACK: Okay. I just -- you know, I had two minor comments, which I'll put in writing. But, you know, throughout the report you kind of differentiate between IOU model, and the merchant model, and there are a lot of claims that the IOU model is somehow cheaper. And I guess I would encourage you to use a little bit more neutral language.

I mean, if you give a merchant a 30-year PPA, you know, sort of similar to IOU ownership, his cost of capital is going to be very similar to the IOUs. And, you know, maybe you can talk about the term of commitment instead of, you know, IOU versus merchant, that's one comment.

MR. MC CANN: That's a good point. A lot of that is that difference in the un -- oh, let me see, the hidden risk difference between the two.

MR. BARMACK: Yes. Yeah.

MR. MC CANN: That is not -- doesn't -- isn't obvious between the two financing approaches.

MR. BARMACK: Yeah. The second comment is, and I think you've been sort of cautious about your claims, you know, about how accurate your estimates of the costs about renewables are, especially relatively new ones, but I think you could be much more guarded about your estimates of the installed costs of some of the newer conventional technologies.

I was surprised and I thought the result was completely counter intuitive that, you know, that you're showing the installed cost of an H class combined cycle to be lower than the cost of a normal combined cycle.

I mean, we're a partner with GE and one of the few sort of existing H class projects, and I found that estimate counter factual and counter intuitive.

MR. MC CANN: Actually, that particular comparison --

MR. BARMACK: Yeah.

MR. MC CANN: -- we actually would be very interested in talking to you because the only H class cost estimate that we have is from EIA, and it’s not survey based, it’s not experience based, whereas our conventional, the F class type combined cycle plants we have --

MR. BARMACK: Right.

MR. MC CANN: -- substantial experience. And so we don’t believe that they’re entirely comparable. And that particular cost comparison, we would actually like much more information about actual experience with the H class.

MR. BARMACK: Well, I think both with the H class and the LMS 100, you know, fundamentally, you just don’t have a lot of data because there aren’t a lot in service. And so, you know, rather than -- you know, maybe you should just have wider bands or -- but I think having estimates of the cost of those technologies, in the case of the LMS 100, that’s lower than OLM 6000 cost, and in the case of an H class that’s lower than an F class, that just doesn’t feel right, maybe you want to do a reality check on those estimates.

MR. MC CANN: Yeah, so if you can provide us where we can do that reality check, we would much appreciate it.

MR. BARMACK: Yeah, well I mean, you know, because the things fundamentally don’t exist, I think you’re going to have to rely more on engineering estimates and what the vendors say than on data, and that's probably not your preference.

COMMISSIONER BYRON: Mr. Barmack, thank you for coming.

MR. BARMACK: Sure.

COMMISSIONER BYRON: I'm curious, if I may ask you a couple of questions?

MR. BARMACK: Yes.

COMMISSIONER BYRON: I mean, things like you're one of the few merchant builders that's still successful, let's say, in going forward with proposals here in California; do we have things like the construction inflation over the last couple of years right?

MR. BARMACK: Well, you know, in just following our own projects and also I've been involved in sort of vetting the MPR that the Public Utility Commission put together, I think your -- both your -- both the simple cycle results that are in the current draft of the report and the standard sort of combined cycle estimates that are in the report -- and I'm talking about installed costs, because I'm still not comfortable with the financing assumptions and the levelization calculations.

But with respect to installed costs, I think they're in a low to reasonable range.

COMMISSIONER BYRON: Just could you -- good. And

I’m curious, how much -- can you give me a sense of how much information because -- let me back up.

There seems to be so much sensitivity around these costs and yet here we are at this Commission, who really doesn’t have a dog in this fight, we’re trying to understand these costs so that we can do these kinds of analyses going forward, make the correct policy decisions, and we always struggle to get access to information.

How much information that you provide, let’s say to -- in your bid process is competitively sensitive versus what you’re limited to talk about because you signed a nondisclosure agreement as part of your proposal?

MR. BARMACK: Um --

COMMISSIONER BYRON: In other words, how forthcoming could you be with information about your costs?

MR. BARMACK: I suspect not all that forthcoming.

(Laughter.)

COMMISSIONER BYRON: But why? Because it’s competitive or --

MR. BARMACK: Yes.

COMMISSIONER BYRON: -- because you signed a nondisclosure?

MR. BARMACK: No, because it’s competitively sensitive.

COMMISSIONER BYRON: But yet, you come to this workshop because you want to make sure we get it right?

MR. BARMACK: Yeah. Well, I mean there are lots of ways this filters through to policy. And I mean, it hasn't happened yet, just to give you an example -- I mean, it hasn't happened yet in California, but to give you an example from another market, you know, in the east, where there are formal capacity markets, you know, all different parameters of the capacity markets, like price caps, and price floors are tied to exactly these kinds of estimates of the cost of new entry.

And, you know, in California the influence of these kinds of estimates is a little bit less direct but I mean, yeah, they can have a major impact on us, so that's why I'm here.

COMMISSIONER BYRON: Well, we welcome your comments and information to the extent you feel you can provide it.

MR. BARMACK: Sure.

COMMISSIONER BYRON: Even if it's just ranges.

MR. BARMACK: Yeah.

COMMISSIONER BYRON: As I said, I think your company is an important contributor here, in California, and we would certainly value any information that you could provide us to help us be more accurate.

MR. BARMACK: Okay, we'd like to help you to the extent that we can.

COMMISSIONER BYRON: Good.

MR. BARMACK: Okay, thank you.

COMMISSIONER BYRON: Thank you.

Now, I hope I didn’t scare anybody off, but we welcome more comments and questions.

MR. SWAIN: Yeah, hi, I’m Ken Swain, with Navigant Consulting.

I just had a clarifying question for Richard. You mentioned that you used the TAC, the transmission access costs, in your assumptions, and I went back and I was looking at the Cal ISOs, I think it’s the March 2009 TAC, and it didn’t look like I jived with what you had in there; I was just wondering what your source data was for that?

MR. MC CANN: The TAC, you mean about the tariffs or about the interconnection costs?

MR. SWAIN: The TAC, the transmission access costs?

MR. MC CANN: I believe that we actually pulled that from the -- it’s about four or five dollars a megawatt hour; is that right, I think? I remember seeing that --

MR. SWAIN: I just had some notes when I was reading that and went back and looked.

MR. MC CANN: Yeah, I believe we pulled it from that tariff, from the March 2009 tariff.

MR. SWAIN: Okay.

MR. MC CANN: I mean, we might have used a somewhat -- I mean, we might have used an average or something, but the range between the different parts of the control wasn't substantial from what we had.

MR. SWAIN: Okay.

MR. MC CANN: And you can look at that in the model where we concluded that component, if you go to the -- there's a page called the -- it's probably on the plant data input page, and that has the estimate, the cost on that page.

MR. SWAIN: Okay, thank you.

MR. HUGHES: I'm Evan Hughes, consultant in biomass and geothermal.

There was a curve that showed the solar PV being the one that really was coming down in costs when you went out to the future, I think it was the dollars per kilowatt number. There was another one that sloped down on that graph, but not nearly as much, and I'm wondering what that other one was and then I have a comment on the solar.

Yes, that looks like it. What's the two with the lesser slopes decreasing over time?

MR. ALVARADO: You're indicating this one over here?

MR. HUGHES: Yeah, and there's a --

MR. ALVARADO: That’s the onshore wind classified.
MR. HUGHES: That’s onshore wind, uh-huh.
MR. ALVARADO: This one in the circle is the parabolic solar.
MR. HUGHES: The parabolic solar, okay.
MR. ALVARADO: And the one that takes the biggest dip is the -- yeah, the PV, central station PV.
MR. HUGHES: Central station PV, okay.
On the PV, I’ve heard for years that there’s been a trend that’s gone back 20, maybe 30 years by now, of approximately an 18 percent decrease in dollars per kilowatt as you double the volume of production. Is that the basis for such a steep decline on that or can you say?
MR. ALVARADO: I’ll defer to our KEMA consultant.
MR. O’DONNELL: Hi, I’m Chip O’Donnell with KEMA, Mr. Hughes, thank you for your question.
In terms of the experience curve there are a number of experience-based curve studies that have been published, not just over the last several years, but over a long period of time.
And there’s a relatively constant learning rate which is roughly around 12 to 18 percent, and it depends which study you use --
MR. HUGHES: Per doubling, you mean?
MR. O'DONNELL: Per doubling, that’s correct.

The other impact of that is when you're looking at cost of generation you're also looking at not just the overall technology impacts, but the installation costs that are associated with that, as well.

And so what we did, as we developed the experience curve effects for solar PV, is we looked at a number of different issues. One was the downward trend in module costs over time, and that's being driven by technology cost drivers, as Mr. Braun had correctly outlined in his presentation.

So you're getting some technology drivers there, but you're also getting some experience curve in new approaches to PV, such as maximum power point tracking, you know, different inverter technologies, and so forth.

And so what we did was we took the base learning assumptions, and I would say the 18 percent is in the range. The numbers that come to mind are between 12 and 18 percent for doubling.

And then we looked at sensitivities around some of those key cost drivers in developing what we call a modified progress ratio, which is really a modified burning effect.

Okay, so I'd say the 18 percent is within the range and the balance of the numbers that we used.

MR. HUGHES: I have a detail on that curve. I've heard that it's possible for an incentive to actually increase the cost because it builds up the demand to take advantage of the incentive and then the suppliers don’t have it right away, and so that can result in the trend line not being followed for a while until the supply catches up.

And then there was a recent, or I guess two or three years ago, lower supply of crystalline silicon --

MR. O'DONNELL: Silicon.

MR. HUGHES: -- that caused a -- have you or Mr. Braun, the PIER project studied that and been able to observe what’s happened in the last two years on that, and are we back on the trend line or not?

MR. O'DONNELL: Actually, what I’d like to do is call up Mr. Pete Baumstark, who is one of our principal researchers on the project.

And the answer to that question is yes, but Pete can provide some more detail and color for the group.

MR. BAUMSTARK: Hello, I’m Pete Baumstark, from KEMA.

You know, see, one of my other jobs is I evaluate equipment eligibility requirements for the CSI program, through another contract with the CEC, and I speak with manufacturers a lot about their PTC ratings, and their modules on the list, and at least the -- one for one, the feedback I’m getting is, yes, two or three years ago it was a buyers’ market -- or excuse me, it was a sellers’ market for PV.

Over the past six, eight months it's reversed. You know, they -- off the top of my head I can't give you actual numbers, you know.

Certainly, there's a refined silicon capacity, there was an issue two, three years ago, that's caught up.

There's the -- you know, there's basically the financial crisis, you know, which basically transformed the market more into a buyers' market.

So, you know, many of these manufacturers are -- you know, basically, they're trying to gain a competitive advantage because it's a lot more competitive right now. Does that --

MR. HUGHES: Thank you.

MR. CAMPBELL: Hi, my name is Matt Campbell, with SunPower.

Just a couple of comments, first of all on behalf of SunPower, we really appreciate this very important work and we understand the complexity in doing this sort of LCOE modeling in that it requires, as it was mentioned, that you're a technologist, an economist, with insight into commodity, prices, and exchange rates, and all the other assumptions that drive the results.

Just quickly on that last comment, about the module experience curve, we did see several years ago, as it was mentioned, that because of the price of polysilicon and the global shortage of PV panels we did go off the experience curve, and we modeled this experience curve and we've seen that we've snapped back to the experience curve as you would expect now.

It was a combination of massive increase in supply, with sort of a slow down caused by the macro economic environment, as well as some policy changes, most notably in Spain.

So one question was -- or one question was posed earlier, which is whether this LCOE analysis should be revisited every two years or sort of kept in a real-time basis; and I think we would feel that it should be a real-time analysis because things are happening very quickly.

And I was just jotting a few notes on what's changed between the April workshop and today, which is only four months.

And a number of things are happening sort of macro in the industry. One for SunPower is that we've actually just finished our first, what we consider utility-scale PV plant, which is a 25 megawatt facility in Florida, we energized the first blocks last week.

And what that sort of speaks to is that although we've been going down a module experience curve, on the power plant side we're sort of at the top of the curve because nobody’s built, you know, these photovoltaic power plants on the scale of a hundred or 500 megawatts, as we’ve seen.

So I think that bodes well for a very aggressive cost trajectory for the single-axis photovoltaic power plants that are mapped out here.

The second is in terms of global finance we are seeing a reemergence of project finance. There’s been a 50-megawatt project that’s been financed in Germany.

In our own case, we’ve announced a financing arrangement with Wells Fargo, so that’s an encouraging sign.

And I think what it speaks to is that as an asset class, investors like renewables and, in our case photovoltaics, because of its ability to generate predictable returns. So we’re not out of the woods yet, but there’s some good signs.

Another interesting point to note is the explosion of photovoltaic power plants announcements, so it’s like actually on the front of the New York Times today. But in China we’ve seen over a gigawatt announced. And at the rate we’re going, probably many more gigawatts will be announced in the not-too-distant future.

In California, I’d have to do the math, but it’s probably between 500 megawatts and a gigawatt has been announced for photovoltaics in California, so again, this concept of the scaling of the PV power plant.

And then in terms of commodity prices, which are a key input to construction costs, we’ve actually seen copper and steel rebound, which speaks to the difficulty of anticipating the constructions cost years into the future, and that applies to both fossils and renewables.

And then in terms of transparency into the actual cost of the power plant which, you know, being an industry we do closely guard our costs because it is so competitive, but there have been some public announcements between April and now.

In our own case, we announced that by 2014 the cost of the photovoltaic panel, which is sort of the steam generator of the photovoltaic power plant would be less than $1,000 per kilowatt DC, so which is -- would be quite a good cost for a silicon, high-efficiency silicon panel.

And our competitors have made announcements as well for solar, made some new announcements in June that were quite -- quite interesting, and we’ve seen announcements throughout the world.

So I think that in terms of your challenge to get the industry costs, there are more public announcements that should make it easier to model, and then we’re happy to help from the industry.

In terms of assumptions used in the modeling, we definitely agree that it’s just highly sensitive to the assumptions and we’ll provide some written comments on some of the assumptions.

But we think there’s opportunities in the assumptions used in the capital costs, on the capacity factor. Obviously, whenever we site a PV power plant, we put it in a place that can deliver the highest capacity factor, because that delivers the best economics.

On the O&M we think there’s opportunity.

And then one of the biggest challenges is on the weighted average cost of capital, and this was alluded to. You know, as an asset class, photovoltaics as a power plant are relatively new. Wind is pretty mature. But I think investors are getting their hands around what’s a required rate of return on a PV power plant.

And we are seeing, we’ve seen public statements by leading banks on sort of different financing assumptions depending on different technology.

So eventually you could see different spreads based on technology class, which is interesting. And I think it just speaks to whatever the perceived risk is of the different technologies.

And then there are other variables to keep in mind, there’s the new Federal Loan Guarantee Program, so if you have a plant that has a significant amount of leverage and then the government is guaranteeing, that's going to lower your spread to something nominally above a treasury, which could -- you know, since in the case of the PV plant it's essentially all capital cost, you're super-sensitive to the cost of that capital.

So and, yeah, so thank you.

COMMISSIONER BYRON: Mr. Campbell, thank you, that's very helpful. And we welcome information that you're willing and able to supply.

A quick question, if I may, with regard to, for instance, the 25-megawatt plant you just are energizing in Florida, is that with an investor-owned -- a power screen with an investor-owned utility?

MR. CAMPBELL: That will actually be owned by Florida Power and Light, and so they rate base the asset, yeah.

COMMISSIONER BYRON: So is this cost information associated with that -- I'm sorry, not cost. The purchasing information associated with that publicly available?

MR. CAMPBELL: That's a good question, I'm not sure how much of that is public, but that would be easy to find out, yeah.

COMMISSIONER BYRON: We're looking for information wherever we can find it.

Well, thank you, thank you for being here, very helpful.

MR. ALVARADO: Any other comments?

MR. MINASIAN: Good morning, Raffi Minasian, from Southern California Edison. I was tapped as a last-minute replacement, so I have a couple questions from colleagues, who may or may not be listening, but I need to make sure that I'm here.

(Laughter.)

COMMISSIONER BYRON: Forgive me, Rocky, what was your last name again?

MR. MINASIAN: It's Raffi, actually, Raffi Minasian.

COMMISSIONER BYRON: Minasian, thank you.

MR. MINASIAN: Yes, you can write that down.

I was going through the draft staff report and I think you showed some of the breakdown for some of the levelized costs, a comparison for '07 and '09, and one of the new items there was the AP 1000 power, the nuclear entry.

And we had a couple questions, one was, you know, that the cost appeared to double in comparing '07 and '09, whereas the instant cost didn't seem to go up quite as much, and I was wondering if there was any insight as to why, why the increase or --

MR. ALVARADO: I'm glad Chip's here today.

MR. MINASIAN: Thank you.

MR. O'DONNELL: That’s a great question. And, you know, in our analysis we refer to nuclear as an issue-filled wildcard in California. And nowhere so has it been more real than the changes that we saw between 2007 and 2009.

Most of the research in the 2007 IEPR, and it was part of our task at KEMA to really look and evaluate that research, the research was done correctly in 2007, and a great deal of it was done based on the 2003 landmark study from MIT around analysis of nuclear plant costs, along with other DOE and other publicly available research sites.

We looked at that research at the time and said absolutely, it’s -- for when it was written and the timeline it was written, that was the contemporary analysis that was publicly available, and so we concurred with that analysis at that time.

However, what happened between 2007 and 2009 have been substantive changes as nuclear undergoes its emerging renaissance in our energy debate.

And I’m not here to opine for or against, but present what factual evidence we have.

There are a number of issues that have taken place since then. There were landmark updates to the 2003 MIT study in 2008.

There are concerns over the timeline that it will take to properly apply for a COL, to get permitting and planning permission approvals, and then to actually build the plant.

And one way that that manifests itself is in -- is in the -- the NRC currently states today it takes six years to build a nuclear plant. And I think there are numerous studies, including one recently provided by the Vermont Law Center, that's in our research, that shows that, you know, those estimates have not been borne true in fact by actual experience.

And so when we looked at the inputs into the cost of generation model, one of the things that we did was we looked at the NRC data for time and amortization time, allowance for funds during construction to actually build a nuclear plant.

And we believed, the research team believed, that six years was not sufficient time for that in California. And quite frankly, probably throughout the country.

And what we did, as the best reasonable proxy for that, in terms of nuclear plant costs, is we used the French model, and the French model is based on a nine-year construction program. Three years fully up front to license, permit, go through environmental impact assessments and then six years, which is the NRC standard, for actual building. And the construction spend and flows of dollars go accordingly with that type of schedule.

We think that may not be enough, it may, it may not be. But our research team assumption, in discussion with the Commission, is if it takes longer than a decade to put a nuclear plant into operation, the investment appetite might not be that large.

So there are a number of changes in terms of how we viewed nuclear, based on updates of information that happened since the 2007 IEPR, along with newly emerging supply chain issues that have been published by the DOE and the NP 2010 study, where they looked at critical supply shortages, all of those things put together have driven the costs up.

MR. MINASIAN: Another question regarding that same technology. The -- somewhere in the staff report it goes over the depreciation schedules and one thing that stood out to us was that the booked depreciation seemed comparatively low at 20 years, as compared to the equipment life, which is at 40 years.

And one of the questions was why is the depreciation schedule seemingly lower; well it is lower, than the equipment life?

MR. O'DONNELL: I want to make sure I understand, the booked depreciation life at 20 years?

MR. MINASIAN: Correct.

MR. MC CANN: Actually taxed.

MR. O'DONNELL: Yeah, that's what I was thinking.

MR. MC CANN: I think the tax depreciation is 20 years and the booked depreciation is --

MR. O'DONNELL: Is 40 years.

MR. MC CANN: -- 40 years in the model.

MR. MINASIAN: I'm sorry.

MR. MC CANN: So is there an issue about the -- I mean, if Edison wants information about tax depreciation treatment on nuclear, we'd appreciate more input on that, you know, because it's not -- it's not immediately obvious from the IRS information as to how that's treated.

MR. MINOSIAN: I'm sorry, I misread numbers, it was on the tax side. But yeah, it was the 20 years there.

Well, then certainly we'll provide some written comments then to that point.

MR. MC CANN: Good, good.

MR. MINOSIAN: Another quick question. Different technology, on the simple cycle side, it mentioned several times in the report that one of the shifting of costs went from the variable and then for the fixed O&M specifically on the simple side, and there's a big difference there, it gets shifted to the fixed.

One of the questions we had was is there a way of capturing that difference either, you know, per dollar per kilowatt year or by megawatt hour?

MR. MC CANN: The model has the variable and fixed O&M costs broken out in comparison to dollars per kilowatt year and the dollars per megawatt hour for each component on the output page in the model, so you can actually look at that difference in the model.

MR. MINOSIAN: Okay.

MR. MC CANN: And one of the things we found though, when we shifted, even though it looks like there's this big shift internally, the final number shift is no significant for the combined or for the --

MR. MINOSIAN: Right.

MR. MC CANN: And the bottom line dollar per megawatt hour number is roughly the same.

MR. MINOSIAN: Yeah, we've got internal reporting that we do and so they tend -- we used the '07 model and so moving forward we wanted to -- we wondered, given the shifting of the costs, whether there was a way of getting a break down there so we could accurately do a comparison.

MR. MC CANN: Right, I think that the information you need is actually in the model, that you'll be able to -- you'll be able to look at the '07 model.

And the '09 model's laid out almost exactly the same as the '07 model.

MR. MINOSIAN: Okay.

MR. MC CANN: And you'll be able to look at that comparison. And the underlying data is almost the same, what we did is we went back to the '07 survey data and looked at the comparisons -- looked at our O&M costs again, and looked more closely at it and said that our breakdown in '07 just didn't seem to stand up to the analysis that we had.

And looking at, also there is in the report a comparison of the O&M costs compared to other agencies, like the Power Planning Council, the Eastern ISOs, some other entities, and our breakdown really didn't match up with their breakdown.

And looking at our data we could -- we felt that we had to go with the breakdown that was more akin to how the other planning agencies and regulatory agencies are breaking down those costs.

MR. MINASIAN: Okay, thank you.

COMMISSIONER BYRON: Mr. Minasian, thank you for being here.

A question or two, if I may?

MR. MINASIAN: Sure.

COMMISSIONER BYRON: Should we read into your first question that we'll see an application for certification soon for a nuclear plant, from Southern California Edison?

MR. MINASIAN: No.

(Laughter.)

COMMISSIONER BYRON: A more serious question, and I was really pleased to hear that -- wait, before I finish on nuclear, I think it’s worth saying that was a very good answer.

I heard a presentation a couple of weeks, at an Electric Power Research Institute Utility Executive Seminar, down in Los Angeles, in fact, the CEO of Edison International was there as well, you may have heard the same presentation. South Korea, for instance, is embarking upon a major nuclear program. They’ve got their construction times down to about 48 months.

And, of course, as Commissioner Boyd points out to me, it’s a different style of government. But they’re attempting to follow the French model and have a very successful program going forward.

But I think you’re correct, it’s going to be very different here in the United States and, certainly, in California.

MR. MINASIAN: Right.

COMMISSIONER BYRON: But I was very pleased to hear that you indeed use our ’07 model, and it sounds like you have plans to perhaps use the ’09 model as well, if it serves your interest.

You have access to a great deal of information as well, because you do compare solicitations for all these different generation technologies, and to the extent your company is willing to share some of that information in the form of comments that we can digest here, we're very interested in them.

And I've talked with some of your executives about this, we don't want to get into the competitive aspects of this and cause difficulties for your customers, but ranges of numbers, giving us some indication if we're doing tax treatments correctly, as you understand them as well --

MR. MINASIAN: Sure, sure.

COMMISSIONER BYRON: -- that could be very helpful and could help this Commission make a much more robust model that could be used by you and others.

Any comment on that?

MR. MINASIAN: I appreciate the comments and I will definitely take that back and we will do everything we can to assist and cooperate.

COMMISSIONER BYRON: We appreciate your being here. Will we be hearing from you at all again, later today?

MR. MINASIAN: I'm not sure about later today, but I will be here all day.

(Laughter.)

COMMISSIONER BYRON: Okay, good. Thank you.
MR. MINASIAN: Thank you very much.
MR. ALVARADO: Any other comments or questions?
Otherwise, I propose that we open it up to the folks that are online.
COMMISSIONER BYRON: So those on WebEx, how should we do it, do they raise their hand online or do you unmute?
MR. ALVARADO: I guess we're just going to unmute everyone. And if you do have -- anyone on WebEx, if you do have any questions or comments, please speak up and introduce yourself.
MR. LEWIS: This is Craig Lewis, I had my hand raised on the WebEx, I'm not sure if it shows up in there.
But this is Craig Lewis, with Right Cycle, and I wanted to ask a question about the -- concerning the cost. The gentleman from SunPower made some excellent points, I thought, with respect to solar, and with all the activity that's going on in California right now around feed-in tariffs and bringing some of the feed-in tariff success that's been done in Germany and throughout Europe, and other parts of the world to California, it seems to me that we need to pay really close attention to that.
And one of the things I wanted to ask about was the cost per watt figures that we've been using for solar, I think, if I'm reading the chart correctly, it looks like

we’re using $4.50 in installed watt, which I think is accurate for California right now, but that curve is going to come down quickly.

The Germans are doing deals under $4.00 a watt already, so they’re at least 50 cents better per watt because they’ve got so much scale that’s being driven by the feed-in tariff. And when you drive the scale that balance, the set-down experience curve comes down very quickly, as does the module curve.

And also with the feed-in tariff you have very low parasitic, the parasitic transaction costs are extremely low, with a four-page contract which they use in Germany.

And so my question is how much attention is being paid to how much faster that solar experience curve can be driven down once we get a comprehensive feed-in tariff in California?

COMMISSIONER BOYD: Once we have a feed-in tariff.

MR. ALVARADO: Chip will come and answer this question.

COMMISSIONER BYRON: Well, the key -- while he’s coming to the podium, as Commissioner Boyd said, the key to that is the quote, once we have a feed-in tariff, quotes. That’s a policy issue, yes.

MR. O'DONNELL: This is Chip O’Donnell, that you for your question. If I truly knew the entire answer to that question, I probably would not be here, I'd be on Wall Street.

The one thing I would suggest is that there are many collateral effects in markets that can drive the experience curve. And as we discussed early, as we were planning out the cost drivers with the Energy Commission staff, one of the things that was noted in our conference call discussion was that disruptive events can change, materially, the experience curve assumptions and projections that we have outlined in the research.

And I would agree with the caller that a feed-in tariff could be one of those type of market events that could provide a disruptive influence to the market, and that could drive costs further down in an accelerated fashion.

Yeah, I don't think it's guaranteed because, as we heard before from the gentleman from SunPower, you know, there are macro and micro economic effects in terms of costs, supply/demand, raw materials that can all play in.

But I think one of the things that we've learned from the European experience, and certainly KEMA has that, as a global energy consulting firm, is that feed-in tariffs can drive markets.

And so we would agree with the assertion, quantifying that, however, is somewhat of an uncertain thing at this point.

MR. LEWIS: So perhaps the conclusion is that given that these, you know, helpful disruptive events, like a feed-in tariff, can change the market pretty much instantaneously, that that would be a good reason for doing a constant monitoring of these cost experience curves.

MR. O'DONNELL: I think the question there would go to pace of change and I think that's more of a policy issue and question than it would be for a research question.

The thing that I can say, just from a feed-in tariff stand point, is that feed-in tariffs are not free and implementing them implies some form of societal cost somewhere. And so it's a cost-benefit analysis, which ultimately becomes a policy issue in its implementation. And I would leave it at that.

In terms of pace of change, you know, the other question is balancing out the cost of monitoring real-time versus the benefits that the State will get by doing so.

COMMISSIONER BOYD: Good answer.

COMMISSIONER BYRON: Mr. Lewis, Commissioner Byron. Very cleverly worded question, but I think the answer was very good, also. And there is societal cost associated with this.

And as Commissioner Boyd pointed out earlier, if you'd heard, he's learned that the Spanish government is underwriting a great deal of the cost associated with the feed-in tariff that they've promulgated there.

I have a question for you, what's Right Cycle?

MR. LEWIS: Right Cycle is a advocacy consultancy and it's essentially my own firm, which I formed earlier this year in order to primarily promote the AB 1106 feed-in tariff bill in California. And as you know, Commissioner Byron, I was the Vice President of Government Relations for GreenFault, a solar technology company based in San Francisco, prior to forming Right Cycle.

And just one quick note in response to what Commissioner Boyd said, and I didn't hear that, I apologize, I was not able to participate in the whole conference here, but with respect to feed-in tariffs in Germany, the all-in technology that is actually priced above regional rates is the solar PV. All of the other technologies are priced below the regional rates and are being driven down further and further each year, as is solar PV, and before long solar PV will be priced below the retails rates as well.

So all of these technologies, given enough time, are going to actually be providing significant and --

(WebEx interference.)

COMMISSIONER BYRON: That's all right, Mr. Rosen, we have you on mute on all the calls, we get a lot of extra information.

We need to ask all the other callers that are on to please be on mute or be quiet at this time. Go ahead, Mr. Lewis.

MR. LEWIS: So I'm not sure how much of that got boggled with the other announcement, but my point is that the societal benefits and costs are actually extremely favorable with respect to feed-in tariffs, as long as you do the analysis over more than a couple-year time period, which I think is to be expected for any type of major policy, like a feed-in tariff is.

COMMISSIONER BYRON: Agreed. And this Commission is not altering its position or recommendations. I think you'll see additional recommendations in this next IEPR.

But Mr. Lewis, unless you're not done, I'd like to thank you for your question and also for your continued involvement in this issue. I'm pleased to hear that you are still involved in advocacy issues around feed-in tariffs.

MR. LEWIS: And thank you for your kind comments and also for your tremendous leadership on these and many other issues. Commissioner Byron, thank you.

MR. ALVARADO: We have Jim Farrar, that's on WebEx. Mr. Farrar, are you there?

MR. FARRAR: I'm sorry, I don't have any questions at this time.

MR. ALVARADO: Any other comments or questions from WebEx?

Looks like I think we’re done with the comments.

COMMISSIONER BYRON: Good. Put them all back on mute, please.

We’re just checking with the agenda. We’re a little bit ahead of schedule and I was just wondering if we could go ahead and start, and take a breaking point in about 25 minutes for lunch, if that works with the next presentation, otherwise we could break early for lunch.

MR. ALVARADO: Either way I think we’re fine, either continuing right now or after lunch.

COMMISSIONER BOYD: Is there a convenient, roughly half-hour segment?

MR. O'DONNELL: We can make one.

COMMISSIONER BOYD: Okay. Well, why don’t we get a jump on it then, for a change.

COMMISSIONER BYRON: Good, thank you. Let’s go ahead and begin and we’ll plan to take a break for lunch after about 20 minutes.

MR. ALVARADO: We just have to load up the slides right now.

MR. O'DONNELL: Good morning, my name is Chip O’Donnell, I’m the Vice President for Power Generation Services for KEMA, and KEMA is an international energy consulting firm, and we’ve been working with the Energy Commission in terms of the entire Cost of Generation Study, and today we are here to present on building and community scale renewable technology costs.

And with me is my principal research colleague, Pete Baumstark, who will be presenting along with me. But this is a report that many people have contributed to, among those Karin Corfee, Valerie Nibler, as our project manager, Kevin Sullivan, Nellie Tong, Rick Fiorevanti, and several others.

And we’re grateful for the opportunity to work with the Commission staff and present today to you, the Commissioners and Assistants to the Commissioners.

One of the things I’m constantly reminded of and certainly this project has been transformative in my own experience, is looking at the opportunities that exist in California around renewable energy and the productive application of renewable energy.

I need to look no further than to check all of the portraits and posters around this room. Around this room, all the colorful posters are the dreams and aspirations of our children in terms of -- in terms of energy technologies in the future.

And one of the things that I was reminded of as we went through this research study was the amount of opportunities that exist if we can help make them happen.

And today I’m pleased to be able to present to you not only the cost basis and technology basis for some of these options but, also, we can describe some of the opportunities that may abound if the State chooses to implement the policies and programs that will help nurture some of these emerging technologies.

We have a lot to cover today, so first we'll cover the approach and methodology that we used in looking at these building and community scale technologies.

We first looked at reference documents and one of the key ones that we looked at was the renewables for heating and cooling study from the International Energy Agency, along with a research report on digesters and bioenergy production.

We also recommended, to the Commission, the building and community scale technologies for cost analysis, with a market justification.

And we note that community scale technologies are generally below 20 megawatts, building scale technologies are generally below one megawatt.

We identified the commercial embodiment of these technologies in California. And as you see as we go forward, some of these emerging commercial technologies are just at the barely commercial state, and we'll discuss that a little bit later on as to why that's the case.

And then we looked at the primary commercial embodiments in the year 2018.

And so here you see a very -- a very simple flow chart about our methodology, reviewing research, looking at KEMA project databases, and augmenting data from our own projects, updating renewable energy technologies, gaining industry inputs into those cost drivers, and then looking at market trends for future costs.

Basically, we looked at, in terms of technology selection, is this technology commercially available? Who is using it?

Let's look worldwide and look at where these projects are being initiated?

Is the technology commercial elsewhere, other than California, and perhaps other than North America, is it globally viable?

And then looking at what would be viable in the State of California.

Looking at this list of technologies, by no means, and I think as Mr. Braun correctly stated in his presentation, the renewable energy landscape, and particularly at building and community scale, offers an awful lot of options, and so it took some work to narrow those options down to a subset of true commercially viable technologies that could be utilized in terms of policy decisions and implementation going forward.

So we know that there are many renewable energy technologies at building and community scale, these are the ones that we thought offered the most commercial viability in the State of California.

One of the things that you'll see is that there are a few thermal technologies that are included here, one of which is solar integrated space and water heating, solar residential water heating, and geothermal heat pumps.

And these thermal technologies generally displace, they're displacement technologies, and they either displace natural gas or, in some cases, electricity and natural gas.

And so one of the things you'll already see is the less discrete nature of building and community scale renewables versus utility scale renewables, where things tend to be packaged a little bit cleaner, a little bit better, not a lot of variables in the mix, or at least fewer variables in the mix.

As we go to building and community scale, those discrete nature of projects tend to diverge.

We found in our research, through the course of this study, a number of unique issues that bear mentioning as we look at the journey from utility scale renewables that we covered in our April workshop to today, as we cover building and community scale.

We've already talked about the technologies not being as discrete. One of the things that you'll see is that because a lot of these technologies are new or substantive difference -- differences to existing technologies and you'll see that for example in some of the cooling and thermal technologies, they often need incentives to promote adoption.

And the key issue around market incentives to promote renewable adoption is if they're going to be implemented our view, as a research team, is that they need to be consistent, because the consistency of an incentive provides basically a market driver to the industry, to developers, and to commercial and private installers.

Absent that, the market perceives that as risk.

And so what you'll see in the B&C scale technology review is that many of these technologies would benefit from incentives, but need to be done in the right way.

One of the other things that we found is that smaller scale technology adoptions often have a wide range of installers and integraters, and that wide range tends to cause variation in contractor expertise, the scope of work, how contracting is done, which complicate the issue a bit more than it would for a utility scale, which are generally a lot more discrete and well defined.

We see potential for technology advancement in many of the building and community scale technologies.

You'll see that some of these technologies are mature, but some of them are brand-new and only now emerging at commercial scale.

The final issue, and probably one of the most important is that at building and community scale levels under 20 megawatts, what we find is a number of technologies are what we call cross-platform.

A great example of this is geothermal heat pumps, where you require, generally, well drillers to drill a geothermal field, then you've got an HVAC contractor, a piping and plumbing contractor, and a building integration contractor in terms of the control systems in a commercial building. Putting all of those together takes effort and work, which is one of the primary pathways that we see inhibit some adoption of these types of technologies, just too many different people and a lack of one centralized integration system to do it all, also play a role in building and community scale.

So those are some of the differences that we see as we move down the renewable chain into the smaller projects.

The first technology that we're reviewing today, at building and community scale, is biomass, and there we've looked at three technologies. We've looked at advanced digester technologies, primarily in the food industry. And we recognized early on that the food industry really has two variants, one is the commercial food processing industry, meat packing and so forth, meat processing, agricultural processing, and the second involves the dairy industry.

And what we decided to do was to couple them together and look at those together, while still separating out some of the nuances between the food industry and the dairy industry.

The second biomass technology we looked at is a very mature technology, and that's landfill gas power generation, basically taking waste methane from decomposing waste in a landfill, and combusting it to generate electricity.

The third and final biomass technology that we selected is wastewater treatment plant application, again a methane capture and then transfer into power production.

The types of technologies for biomass digesters are fourfold, covered lagoon, complete mix, plug flow digesters, and fixed film digesters.

And one of the things that generally happens is that the application of biomass technology is a discrete and engineered study around the type of application that it represents in terms of the actual application.

For example, you would look at a covered lagoon digester and those are generally done in warm climates, basically a deep pit and basically simple.

Many meat packing industries will use covered lagoon, versus some of the other ones.

One of the things that's happening with advanced biomass technologies is retention time in the digester, itself, is reduced. That allows greater volumes of waste to be processed through the digester and, ultimately, higher production of biogas that can be used for power generation or for other purposes.

And basically, with food waste and waste water, developers are moving toward those technologies with lower retention times, basically to improve the economics, the economics of the system.

And we see that a lot in terms of dairy applications because one of the difficulties in today's market, in driving digester applications, is not just the cost of technology, but also the risk involved in the dairy industry.

And so what developers are doing is they're trying to improve the economics to such a point where it compensates them for taking additional market risk.

Basically, in looking at conventional digesters versus advanced, there are two types of techniques that are being used today; one is thermophillic digesters, basically looking at higher heat loads, generally temperatures of 120 to 140 degrees Fahrenheit. And basically, those systems are ideal for CHP combined heat and power applications at facilities.

The other step is looking at single versus two stage and, basically, the biogas process optimized the PH levels in the digester to basically improve the quality and the quantity of landfill gas that's produced.

Key cost influences. And this is one where we go from a generic look at technology to where are the specifics that really drive the cost.

The first is the type of food waste that's used in the digester, because each type of food waste will vary in terms of its material properties, characteristics, and the percent solids in the waste.

So depending on the type of food waste that is used, the biogas production will be directly proportionate to the level of solids that are in the mix.

The second aspect in terms of cost is capacity factor, and that's really a function of looking at the quality of gas that's produced and the amount of gas that's produced, and so that's one of the reasons why an advanced digester technology increased capacity factors are really a function of increasing the biogas production off of a reactor.

Installed cost is always a key driver in any capital intensive technology, and biomass is no different, basically, looking at $4,000 to $6,000 per kilowatt.

And the other issue, and this was one that we spent some time in researching, is that most industrial applications of biogas and advanced digesters are single-facility food plants. And one of the things we were asked to look at was, is there a role for community scale digesters, where waste would be transported to a centralized location to increase the amount of biogas production at one central facility?

We think that's a good idea, but the practical applications in terms of development and getting industrial companies to transport that waste are highly unlikely.

So we think there are some applications for community scale centralized digesters, however, they're going to be limited in scope.

One of the things you see here in terms of technology description is basically fig growers, in California, looking and constructing a covered lagoon system to use waste from cleaning and rehydration of dried figs, and you can see the lagoon pit being excavated in the first photo, and then the covered lagoon on top in terms of capturing the methane given off by decomposition and then used into production of biogas.

Basically, the advances that are being made in advanced digesters are incremental, and those incremental advances are around better waste decomposition and biogas production.

One of the things that you see, that's unique, is the installed cost range is widely varying. The average cost per kilowatt is about 47 to 48 hundred dollars per kilowatt, with a minimum capital cost that we've found in the $2,000 per kilowatt range and a maximum in the $15,000 per kilowatt range.

And what that really, basically, is a reflection of is the type of technology that's used and the type of food waste that's being decomposed, and the amount of food waste that can be decomposed.

And what we have found is that in terms of digester technologies all of these things are location and site specific, so that is the cause in the widely varying range in capital costs.

Looking at biogas digesters and looking at trajectories, we don't expect the price trajectories for biomass digestion to change dramatically. We think that any improvements that are being made are going to be made incremental, over time. And basically, a lot of it is due to the physical limitations of the current technology.

The production increases that are being made are incremental, but we see those as continuing, but at a slow rate versus what we would see, for example, in solar PV being a lot larger.

And what we also find, and I've found this in terms of actually developing biogas projects in the past, is that every facility, every food processing facility tends to be a one-off. And so the ability to get economies of scale from plant to plant are compromised because of the type of food wastes that are being decomposed, the amounts of food waste that are being decomposed, and then the optimal application of technology to make a project work.

So we see a lot of variations in these one-off projects that prevent there from being a very significant economy of scale effect.

Looking at landfill gas, landfill gas is a very mature technology. Landfill gas operators operate not only in North America, but also throughout the world, and basically one of the main component of the technology is capturing landfill gas from waste decomposition and either injecting that into a gas pipeline or, in our case, looking at it to produce generation.

Basically, the impact of low BTU gas, as you'd see in a landfill, roughly 50 to 75 percent of the heating value of traditional natural gas, basically results in slightly reduced efficiency and combustion, and slightly reduced power output as compared to natural gas.

But the impact on climate change, the impact on costs make it a viable technology today.

One of the issues with landfill gas, we have low installation costs, roughly $2,000 per kilowatt which, for the size range that we're talking about, is a fairly reasonable cost level and that's one of the reasons why the maturing of the landfill gas processing industry has taken hold.

One of the issues in terms of landfill gas recovery operations for generation is that landfill gas, by its nature, is not a very pure substance. And so significant investment in operations need to be devoted in terms of landfill gas cleanup.

And you'll notice something that's there in the slide, called siloxane, and siloxanes are silicon like compounds that basically can plug up and foul power generation equipment, and require constant maintenance in terms of keeping the values of that pollutant down, as well as making sure that it does not compromise any of the mechanical systems.

Most of the technical issues with landfill gas technologies are known. In California, there are systems that range in size from 100 kilowatts in size up to 50 megawatts in size. But the average system is really between 2 and 5 megawatts, and our studies have shown just roughly under 4 is the average size.

And the typical technology that's used are reciprocating engines that would be modified, they're natural gas reciprocating engines and they would be modified for use on the landfill gas fuel.

One of the reasons that gas turbines are not generally used are because of the siloxane issue that we talked about on the other slide, which can plug up very small cooling holes in the hot section of the gas turbine.

The State has about 34 additional candidate landfills that would represent about 136 megawatts, and 194, nearly 200 additional potential sites. And the potential sites, basically, have very low kilowatt capabilities of around 100 kilowatts.

And what happens at that level is that without micro turbines or other small sources of generation, those cannot always be cost effective.

Basically, the key cost drivers in landfill gas technologies are modifications to the engines for the load BTU gas, the engine's susceptibility to contaminants, such as siloxane compounds, the impact of low to medium BTU gas on the engine itself, in terms of wear on the engine.

And generally, while CHP can be utilized in landfills, what we've found in our research is that there generally tend to be fewer opportunities to do so.

And in terms of long-run cost drivers, we don't expect to see the price of landfill gas technologies to dramatically change in the future, because of the maturity of the market, it's a well-known technology and well-applied, and so we don't anticipate any significant experience curve with that over time.

COMMISSIONER BYRON: Mr. O'Donnell?

MR. O'DONNELL: Yeah.

COMMISSIONER BYRON: All this talk about digester gas and landfill gas has certainly gotten me hungry.

(Laughter.)

COMMISSIONER BYRON: What do you say we take a break at this time for lunch?

COMMISSIONER BOYD: Can I ask a question or two on the slides we've done so far?

COMMISSIONER BYRON: Please do.

COMMISSIONER BOYD: Yeah, I've looked ahead and it just gets deeper and deeper, and what it might do to your lunch appetite.

(Laughter.)

COMMISSIONER BOYD: A quick question, your reference to community scale digesters, was that a comment related to all the classes, that is the food classes, the manure, dairies, et cetera, et cetera, or was it more on municipal waste?

MR. O'DONNELL: Generally, the comment referred to collating food and agricultural sites into one location.

Landfill sites, Commissioner, are discrete, as you know.

COMMISSIONER BOYD: Few and far between.

MR. O'DONNELL: But the larger issue comes to convincing private enterprises, that operate typically small, discrete processing locations to aggregate all of their waste, basically double process it, because they're hauling it, and making that economic.

Our experience and our research have shown us that that's -- you know, it's a laudable goal. The mechanics and mechanisms for getting it there seem to be quite problematic.

COMMISSIONER BOYD: It's a goal this agency has been pursuing for several reasons that you're probably familiar with. You know, as you already indicated, the one-off facilities are pretty small.

We've been trying to encourage dairies to -- you know, we've been trying to encourage regional facilities of some kind, and multiple dairies for hosts of reasons, and it usually ends up -- well, it doesn't usually end up, it can end up in an above-ground, rather than a lagoon type facility.

And as you know, in this State we've got significant water problems that cause lots of grief for lagoon digesters if they're not lined. Co-digestion is a really good thing, that is organic foods and manure, and that runs into all kinds of regulatory problems.

And, of course, on-site power generation, using internal combustion engines, which you indicate is the usual practice, run into air quality problems in this State, particularly NOX.

MR. O'DONNELL: Yeah.

COMMISSIONER BOYD: So those of us who deal with this on a, if not daily, weekly basis, have been beating our heads against all those kinds of issues for quite some time.

The latest craze and a positive thing is, you know, collect the biogas, clean it up to pipeline specification quality gas and inject it into the backbone pipeline. That's caught on better but, you know, not all dairies are near the backbone gas system, so they either -- either can go with a regional approach, which hasn't -- a lot of proposals, but they haven't been able to get financing to do them, or you go with on-site generation, and the economics go to heck as soon as you add the air quality clean up. Most small dairy farmers walk from those proposals because of the economics.

Anyway, that was not a question as much as comment, or an inquiry whether you've seen all of the above in your work in compiling this material?

MR. O'DONNELL: Yes, and not just in this research, but also in my development career. You know, I think the idea of a community-based system is a good idea. I mean, it creates the economies of scale that can make a lot of the economics work better.

My experience with private companies and private food companies is that they tend to be small; they tend to be limited in terms of the expertise around energy and energy systems. And because of that, it tends to have a second tier influence versus the first tier influence of making the dairy business or the food processing business work well.

And so you end up with a bit of, you know, good intentions, but difficult to make the intentions into reality. And I think part of that is also based on the economics of the dairy industry, itself.

KEMA was advising a client that was very active in looking at dairy digesters, just this year, and this particular company has pulled away from several projects, typically not because of the economics of the project, the project actually worked, but because of the market risk that they would be taking over a 15- or 20-year period which you would need for financing, and the current hard times that are being felt by the dairy industry in North America.

So, you know, I think it's a great goal. The hard part is, is as you said, Commissioner, there are so many different factors that are weighing in on this that it becomes difficult to gain the type of traction that will help that go.

We think it's a good goal; it's just very hard to get there.

COMMISSIONER BOYD: Yeah, we're kind of hoping solutions to other environmental issues become more and more of a driver. Climate change is a huge driver, but the water quality problems are also a driver.

But, you know, particularly in a farm community, they're interested in farming. This is a nuisance issue they have to deal with.

MR. O'DONNELL: Yeah.

COMMISSIONER BOYD: Thank you.

COMMISSIONER BYRON: Thank you. Let's go ahead and break. Is one o'clock the time? I'm a little bit concerned, it's a little after noon, let's go to 1:10 -- 1:15. 1:15, we're negotiating up there. 1:15 we'll reconvene, thank you.

(Off the record at 12:05 for the lunch recess.)

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AFTERNOON SESSION

COMMISSIONER BYRON: Ms. Green?

MS. GREEN: Are we ready?

COMMISSIONER BYRON: If you’ll all be seated, we’ll go ahead and reconvene.

MS. GREEN: All right, we’ll continue with KEMA’s presentation.

COMMISSIONER BYRON: Mr. O’Donnell, I made sure I had a glass of milk at lunch today.

(Laughter.)

MR. O'DONNELL: And I’m sure the dairy farmers of California appreciate your support. Thank you, Commissioner.

We’re back and we’re talking about building and community scale renewable energy technologies, those technologies less than 20 megawatts, and we’re focused right now on biomass, and specifically, biogas applications from waste water treatment applications.

The basic technology improvements that we see in waste water treatment biogas process is that thermophillic digesters and devices can be used to increase the applicability of this technology.

Basically, all of the current digester technologies that are in force today can be utilized and are utilized, in many cases, at waste water treatment plants across the United States.

There's one that I'm personally familiar with, Veolia Environmental Services, a Milwaukee waste water treatment plant, that they operate from the City of Milwaukee, where they use digesters and power recip engines off of that.

The key to waste water treatment is how do you get scale, and the ability to increase to large systems that are the 5- to 10-megawatt and the around-the-clock operation basically are the key opportunity areas for advanced systems, such as the two-stage digester technology that we talked about earlier.

And basically, in terms of waste water treatment application, some of the key components in our research is that high capacity factors are always a part of waste water treatment operations because they process waste water 24 hours a day, seven days a week, and so there's always a ready source of methane through digestion.

Looking at overall installed costs, we anticipate that costs will range somewhere between $3,000 and $6,000 per kilowatt. But again the key is, is that depending on the nature of the waste, the amount, the volume, the concentration of solids that are in the raw fuel mix, no digester that we've seen is really a standard application, and so everything tends to be customized in its application.

And most waste water treatment systems today employ some form of combined heat and power, or cogeneration. And oftentimes what happens in the cycle for waste water treatment plants and biogas applications is that waste heat from either a reciprocating engine or perhaps a small turbine is used to heat the incoming water and increase the biogas availability, and that improves the overall economics through better thermal utilization.

And then the final issue in terms of cost influence of waste water treatment plants is that the size range tends to be limited in most cases to one to five megawatts overall, and that's dictated primarily by the size of the waste water treatment plant, itself.

When waste water treatment digesters first came out and waste treatment processing options were available, a lot of the early focus for waste water treatment plants were on technologies, such as micro turbines and fuel cells. And this was the subject of an earlier discussion we had, basically, those have all gone by the wayside in favor of reciprocating engine technologies.

And the real fundamental issue is that anything that a micro turbine and a fuel cell can do in this application, a reciprocating engine, or a gas turbine, tends to do it more reliably and more cheaply.

And so the issue there is the market is starting to dictate the choices of technology based on cost and based on reliability.

And as we've talked about before with other biogas and biomass technologies, the type of waste stream and the type of decomposition products that are present in those flow streams impact the biogas generation and the generation of power.

What we see for waste water treatment plants is that because the technology is fairly stable and fairly uniform, even those waste streams are there, cost ranges can go typically from $3,000 to $4,000 a kilowatt, with an average of about $3,470 per kilowatt.

And we also, basically, are looking a minimal experience curve effects over time owing to the maturity of the technology.

We see, again, in terms of the technology cost drivers a mature market, both on the generation side and on the digester and processing side.

The real issue in terms of waste water treatment is that most waste water treatment plants do have the ability to use the advanced two-stage digesters, and part of the reason for that is the skilled nature, itself, of waste water treatment processing leads to a fairly high degree of technical skill among plant operation staff.

And it’s been our experience through the research and through our own project experience that those types of facilities, waste water treatment facilities, often have the type of skilled labor that is required to operate advanced digester technology.

Here’s a picture right now of a typical process in terms of the advanced treatment, and it flows in between the primary and secondary treatments overall, into digestion and de-watering.

And here’s an example of an advanced two-stage digester system incorporated into a waste water treatment plant.

Now to present on solar photovoltaic technologies is one of our principal investigators and researchers, Pete Baumstark.

MR. BAUMSTARK: Thank you, Chip.

My name is Pete Baumstark, I’m with KEMA, I do different forms of energy analysis.

And I’m gong to actually speak about, oh, the PV technologies, wind, hydro, then Chip will come back up to speak about a couple and then I’ll round it off with the solar hot water.

Okay. So, you know, the PV technologies, we actually split it up into three categories. First is the residential fixed tilt. There is -- you know, the things that influence the cost are capacity factors, also the installed costs.

Now, I was able to get the installed costs from the CSI database, so this represents nearly 15,000 systems installed over the past two years, and so the cost we have it quite a range but, you know, with the average of just over $8.00 a watt.

Now, this type of technology, you know, on the average you're talking about a five-kilowatt system, usually mounted on the roof, sometimes mounted on the pole, and you really just have modules and balance of systems, and it's a very simple system.

Now, we already talked about the cost drivers but it's, you know, generally you're talking installation costs. Now, these are going to be significantly greater than your utility scale plants. Residential PV, we're looking at roughly a two to one cost versus the utility scale.

And one thing we are finding is quite a range, you know, especially if you get into systems below seven kilowatts in size, that there's a huge range in the CSI database as far as installed costs.

So here I show the range that we've been seeing for residential systems, and I show a much more modest cost decline over time.

You know, in this case it’s a little different type of technology -- no, it’s not a different type of technology but, you know, when you’re talking the utility scale projects you’re talking about, you know, big bulk purchases, you’re talking about not very many systems installed yet, so you have tremendous potential for learning effects.

Now, for the residential and building scale, you know, there’s a lot of learning that’s been going on so we’re foreseeing a much more modest cost decrease for the residential and building scale.

The next technology would just be commercial fixed tilt. Now, this can either be pole mounted or be on rooftops.

Through the CSI database, the average system installed over the past couple of years is about 138 kilowatts. Now, this is up quite a bit from prior to 2007, just because the CSI program increased the -- increased the cap at one megawatt, so you have the potential for one megawatt systems. Previously, I thin it was 50 kilowatts was the cap.

COMMISSIONER BYRON: If I may interrupt?

MR. BAUMSTARK: Yes?

COMMISSIONER BYRON: Is the only distinction between the technology the fact that it's tilted?

MR. BAUMSTARK: The fact that it's tilted? Oh, okay. No, I call it commercial fixed tilt to differentiate it from pole-mounted tracking.

I do have another technology where I look at tracking for a community scale application, so that's the only difference.

And here we see the installed costs being quite a bit less, about $7.70 a watt, is what we're seeing from the CSI database.

Now, this technology here, I show a picture of a roofing integral product, they're also available in mounting structures that go on commercial flat roofs, as well as give a tilt.

And again, you really just have your modules and your balance of systems, primarily consisting of the inverters.

There is a possibility for electrical storage with these units. We're not seeing a lot of systems with storage capability, they're almost, you know, predominantly net metered applications in California.

So here I show the cost ranges. Again, I give like a -- you know, one thing to note is the capacity factors. Now, I have capacity factors listed here as a cost driver. Now, that is going to depend on location, it will depend on tilt of the system, amount of shading, et cetera.

The values I've gotten for capacity factor for, they're based on a 2006 study of self-generation -- of the installations in California's Self-Generation Incentive Program, and that is the range I got for California, it's about 14 percent to 17 and a half percent is your capacity factor.

And here again I show a -- you know, we're seeing a pretty wide range of installed costs, and I show a cost decrease over time, very similar to your residential PV systems.

And the third PV technology is ground based tracking systems. Now basically, in California, you're going to see about a 30 percent increase in output with a single access tracker versus a fixed tilt system.

One thing about it is if you include trackers, you need a greater acreage relative to the kilowatt hour output than you would with the fixed tilt system, but you get a much greater output per installed kilowatt. So it just would depend on the -- you know, on the land restrictions and how much land you have available, and the cost of the PV system. You can get more output per watt, but a lesser output per acre with the single access tracking.

Okay. You know, one thing I want to interject here is I've been speaking to a few of the program administrators for the CSI, and they've been telling me that -- about performance-based incentive systems under the CSI, and they're seeing very significant payments to these systems.

You know, some customers and some installers, you know, they've figured out that under a PBI incentive, you know, they can do quite well with a single access tracking system. So we're seeing more and more of those in California with the advent of PBI.

One thing we did talk about, capacity factors, it's about a 30 percent increase relative to fixed tilt systems, average in California. And one thing, my analysis included larger systems, I assumed these would be systems above 500 kilowatt would be your -- basically, a community scale system on a tract of land.

My analysis showed you were talking maybe a one dollar increase per watt of installed costs for including the tracker.

Also, as you get into these larger systems, above 500 kilowatt, you are -- you know, costs tend to do down. I did an analysis of the higher output systems for the CSI and found as you get larger, you know, your cost per system goes down. So that's how I derived these particular costs, and I get about $7.30 a watt for this scale system.

COMMISSIONER BYRON: Of course, now we're talking about land, not rooftops.

MR. BAUMSTARK: That's true. That's true.

COMMISSIONER BYRON: Did you factor in the cost of land and mitigation?

MR. BAUMSTARK: I did not factor in the cost of land. I assumed that the building or community owner would -- you know, they would own the land, I did not factor that in.

COMMISSIONER BYRON: Well, but how many, you said 500 kilowatts; correct?

MR. BAUMSTARK: Right, right.

COMMISSIONER BYRON: So just my rule of thumb is that's about four acres of rooftop.

MR. BAUMSTARK: Right.

COMMISSIONER BYRON: And, of course, the pictures you're showing are not on rooftops.

MR. BAUMSTARK: No, 500 -- yeah, four acres, okay.

COMMISSIONER BYRON: I just -- a range of about eight acres to a megawatt kind of number.

MR. BAUMSTARK: Okay, I thought it was --

COMMISSIONER BYRON: My point is your pictures -- your pictures aren't on rooftops either, are they?

MR. BAUMSTARK: Right. No, they would not be on rooftops, they would be on a tract of land for this technology, you would not -- you typically would not use a tracking mechanism on a rooftop.

COMMISSIONER BYRON: And so I ask a question, do you think that we should be factoring in land and mitigation costs associated with that land because now we're -- now we're talking about acres of land?

MR. BAUMSTARK: Yeah, we did not factor it in. That is a good point. That is a good point.

Okay. And here I show the -- again, it's cost trajectories over time, assuming a more modest decrease than we did for the utility scale systems.

Okay, so that rounds it off for the PV technologies. The next is what we call community scale wind.

Now, community scale wind is -- it's kind of a -- I guess I want to call it a tweener. You know, you have your utility scale wind systems and then you also have your building scale wind systems. The building scale wind, you know, we do have a rebate program targeted for that in California, called the Emerging Renewables Program.

And, you know, we do have the Self-Generation Incentive Program that would include some community scale type systems.

So what I did is I took a look -- so when you come up to capacity factors versus equipment costs, there is a big discrepancy between utility scale and emerging renewable program building scale projects, and I'll go through how I went through that analysis.

Okay. And one thing, community scale wind, that refers really to the intention of the development, it's just owned by a community, or certain stakeholders in the community, and not necessarily owned by a third-party generator.

Generally, they range in size from 100 kilowatts to ten megawatts. The definition, you know, really the definition of community wind is more the intent of the ownership than the size, though, but that's the rough range we've been seeing.

Now, there's really two main cost drivers, you have the installed costs, where the turbines themselves are about 75 percent of the installed costs. And one thing with that is the trend of cost for wind turbines has been seeing an increase over the past several years. You know, since about 2002 every year we're seeing increased costs.

There are several factors that feed into that, one of them would be the cost of the dollar versus the Euro, there's commodity costs, there is U.S. manufacturing production capacity, et cetera.

Many of these drivers have been showing a reversal over the past one or two years. But at the same time, the trend has been increase in cost for the turbine installations.

Another, but on the flip side, we are also seeing capacity factors increasing. You know, there are larger turbines coming on the market that drive higher towers, get into better wind resources, and we have been seeing a steady increase in installed capacity factors for wind turbine projects.

COMMISSIONER BYRON: Now, let me quiz you on the capacity factor thing?

MR. BAUMSTARK: Yeah, uh-hum.

COMMISSIONER BYRON: You say a hundred kilowatts to ten megawatts --

MR. BAUMSTARK: Right.

COMMISSIONER BYRON: -- so how many turbines are we talking about?

MR. BAUMSTARK: We are talking -- you know, it will depend on the site. You know, if you're talking a one-megawatt turbine is pretty common so, yeah, in that case you're talking ten of them.

COMMISSIONER BYRON: Okay, so at one turbine the gear box goes out, it's not operating, the capacity factor's at zero until it's fixed.

MR. BAUMSTARK: Right.

COMMISSIONER BYRON: And the farmers and the local business -- local businesses and schools are going to have to make a phone call and get somebody out there, and it could take a while to get it fixed, is my point, and also the O&M costs, I would think, would be substantially higher on a kilowatt basis or something like that. Have you factored either of those things in?

MR. BAUMSTARK: You know, well, as far as the extended capacity factor, it's there within the range, definitely.

You know, one thing I did is I took a look at the -- like the capacity factors we've been seeing for the emerging renewables program, which is pretty low, which would take into account down time, and time to get people out there to fix, and then there is also studies for the utility scale.

So the average capacity factor we're estimating falls somewhere in between that, so that would be the capacity factor is included there.

As far as O&M costs, what I ended up using is the LB&L numbers, they do have -- see, the thing with O&M costs is they increase over time. Like in ten years out you're going to have more O&M than you did at year two.

And their analysis included -- it was an aggregate of community and utility scale projects.

So it is included in there. I didn't necessarily try to dissect it as far as a little bit more for the projects, you know, on people's farms and whatnot so --

COMMISSIONER BYRON: And I think, Mr. Baumstark, there's no right answer to my question, really.

MR. BAUMSTARK: Right.

COMMISSIONER BYRON: I'm just kind of trying to get a sense of how you thought about this process and how you factored these different things in.

MR. BAUMSTARK: Sure.

COMMISSIONER BYRON: Because they're going to operate differently, obviously, at this scale than they would at large utility scale.

MR. BAUMSTARK: They would, yeah.

COMMISSIONER BYRON: Okay, thank you.

MR. BAUMSTARK: Okay. All right. Okay, the cost trajectory. Now, what we are seeing in, as I mentioned before, in recent years the costs have been steadily increasing.

Now, many of the factors associated with that we've been showing reversals, but as of yet, you know, as of the 2008 LB&L study, which is probably the most reliable cost study, they're still in 2008 showing an increase from previous years.

So we do expect a modest increase, there will be some learning effects involved, there's some reversal of the indicators driving the costs, but we still project a modest increase over time for wind turbine technologies.

Okay, next is in conduit hydroelectric. Now, as far as what is meant by in conduit hydroelectric, you know, you were talking specifically municipal water districts, you're talking irrigations districts and whatnot that would include -- you know, it would include generators within their water system.

Generally, we're considering 100 kilowatts to two megawatt type systems.

Now, here the issue with that is, see, a lot of these various water purveyors, they're going to have their resource, you know, the water resource at different availabilities for different times of the year.

A lot of times the irrigation districts you'll have maybe six and a half months where you're irrigating and during the rainy season you're not, so that is all factored into capacity factor.

And here I show a chart showing -- what it's showing is O&M expenses versus capacity factor for these smaller in conduit type systems. And it's all over the map, it can range -- it can range dramatically based on several factors and the water resource that they have available.

So, you know, we got roughly a .51 capacity factor on average and about $11.00 a megawatt hour, you know, in O&M.

Okay, we already talked about a lot of this. But the two, there are basically two main types of turbines. You know, you have your impulse, which basically just gets its power from the moving water. Then you have the reaction, which is a combination of moving water and pressure.

And below these there’s a subset of several other categories. Each design works better with certain combinations of flow ahead than others, so it’s always a matter of just picking, you know, surveying your water resource and then choosing the correct technology for that resource.

And I do have -- in our interim report, I do have a further breakdown of these technologies.

So we already talked about capacity factor and the O&M.

Capital costs, we’re seeing roughly about $2.00 a watt for these types of systems, but there is a significant range. I do have a further breakdown in the interim O&M report and it does break it down per different types of turbines, you know, different, whether reaction or impulse and the various categories within there.

And I have an average for California. There’s various sites that we have been surveying in California and I was able to -- that’s how I was able to extrapolate the cost, or the average cost that we could see.

Now, we’re seeing the in conduit hydroelectric as a mature technology. We don’t foresee there to be a lot of learning effects associated with this. We foresee, actually, the learning effects of these installations will pretty much be offset by inflation, so I’m showing a fairly flat curve.

And those are -- I do have one additional technology that’s at the end. Unless there are any questions, I would want to turn this back over to Chip to go over the integrated space and water heating.

COMMISSIONER BYRON: No. Thank you for the overview.

MR. BAUMSTARK: Okay.

MR. O'DONNELL: Thanks Pete.

As we continue the presentation, we’re now into what I would call the thermal technologies or the displacement technologies. And these are unique technologies that don’t necessarily generate electricity, but act as offsets either for the use of electricity, the reduction of demand, or for the displacement of natural gas.

And the first technology of this type is integrated solar space and water heating. And basically, as we’ve researched this technology, the use of integrated solar space and water heating has good potential to reduce natural gas and electricity use in California, which helps with energy efficiency, which helps with California’s State energy security, as we’ve talked earlier today about the natural gas variations in the State over the past several years.

It also contributes well to climate action goals, not only for the State, but for businesses and utilities across the State.

And so the other issue in this technology is that there are some interesting research developments that aren’t close by, but in the midterm future could offer some very substantial benefits in terms of its applicability to the State of California.

What is integrated solar space and water heating? Basically, what it is, is it’s utilizing the thermal power of the sun to heat not only water for domestic hot water and heating use, but also using that thermal heat to heat space, building open spaces used in climate control systems.

And the key cost influences around the technology are several. First and foremost is the amount of solar collection area that’s needed. In each of these systems, based on the location of the system, where it’s installed, and the solar eradiation characteristics of that site, you basically go through a sizing program and calculate a certain solar collection area which is used for the solar thermal collector.

One of the interesting things about integrated solar space and water heating is that community scale costs for this technology can be high, and they're high based on a number of factors.

There is a developer that developed an integrated solar site for a community, called Drake Landing, and the costs at Drake Landing for delivering heat, this was a proof of concept demonstration, but the cost of delivering heat was about $23 million per MM BTU. It was incredibly high and part of it was it was a large community scale, very similar to a development that you would see in Europe, but the larger issue was there was a massive thermal storage capability that was designed into the system.

And this is an example of one of the things that you see when you go from utility scale, where things are much more discrete, to building and community scale where they're really all over the map, very similar to Pete's hydroelectric graph where everything was scattered.

This is definitely an outlier as a proof of concept demonstration project, but it just goes to show you $23 million per MM BTU is something in terms of capital costs that wouldn't go well.

Thankfully, the application of this technology and other applications is becoming more and more cost competitive.

Another key cost influence is whether the installation of this technology is for a new building or retrofit of existing space. And the large issue here is if you follow lead principles, for example sustainable design in building principles, and you integrate solar thermal collection area into the rooftop of a brand-new building, it’s usually much more cost effective than retrofitting an existing building with those technologies.

And so we see the applicability of integrated solar more so on the new building site, as lead becomes more integrated into building codes across the nation. But also just, frankly, from the cost effectiveness of installing the system in a new building.

Another key cost influence for integrated solar is natural gas price, because that sets the tipping point, that sets the point at where it’s economically beneficial to use the power of the sun to heat water for heating and for domestic hot water versus utilizing natural gas.

One of the big influences that we see in terms of the commercial applicability and scaling potential of integrated solar space and water heating is the fact that today, if you go through the body of research and the body of manufacturers that are promoting this technology, most solar hot water tank systems are sized anywhere between 80 and 160 gallons. And 80 gallons is primarily the type of water tank that you'd use for a large home.

And so when you look at expanding this technology from the residential level into the community or building level for commercial buildings, where it could have potentially more applicability, more scale up work really needs to be done in terms of system size.

Today, the way that's done is either by modularizing these 80- or 120-gallon tanks over and over again, in multiple systems, which is capital intensive, or custom designing a system with larger tankage, and larger piping and networks, which tends to be more intensive on the engineering front.

So that's the balance point that we're at right now in terms of integrated solar space and water heating.

There are really two different types of systems that are used today in the commercial embodiment of integrated space and water heating.

The first, in the upper picture, is what would be called a fluidic or a hydronic system. And hydronic basically means the use of water in a circuit. And what you see is on the very top of the drawing there is a solar collector and then, basically, that goes through a tanking system for storage and then pumping for distribution.

And the pumping happens in two forms. One is for domestic hot water it goes through the normal hot water circuit, just like any other hot water system in any other commercial building.

The second is the boiler system or the heating circuit using hot water heat as the medium of exchange versus forced air or other technologies.

So that’s really the fluidic system, which is probably the most prevalent commercial embodiment in the country and in California.

The second system is called either transpiration or an air system. And realistically, all that is, is basically using light absorbing metal panels that absorb the solar radiation and heat the surrounding air.

That surrounding air is brought into a building for space heating and/or is used to pre-heat hot water in the boiler system for domestic hot water use. And both systems have applicability for this type of technology.

One of the key things that we see in terms of -- in terms of this technology is, and this is something we mentioned earlier in the presentation, a fragmented supply or business model really tends to limit the applicability of this technology so far in its commercial embodiment, to the point where today it’s only a marginally viable commercial technology.

It is being utilized; you can find a numerous number of small integrators that are actually applying this technology both at residential and small commercial scale.

But when you think about how this technology's applied, it creates issues.

Let's look at the air system. For the air system you need a building and a roofing contractor to be able to install the solar thermal panels. Then you need to bring that into an HVAC contractor who can take that heated air and process it through the HVAC system of a commercial building.

If you're looking at a water system, it even becomes more complicated because you've got a roofer to install the solar collector area; you've got an engineer to size the solar collection area and the panels. You want to make sure that those panels are certified so that you can use that for tax credit purposes.

Then you've got a plumber to pipe everything and you've got an HVAC contractor to put in the boiler system.

When you look at that supply chain of events for one homeowner, or one small business owner, or one commercial building owner to install the system, it becomes an impediment. And in our view at least, and what the research is telling us, it's one of the issues that become a factor in terms of commercial adoption.

We've talked a lot about this. The one other issue is that limited standards currently exist for this type of equipment. So consumers and people who would be interested in implementing this technology do not yet have a consistent set of safety equipment and performance standards.

And while those are being worked on right now, you know, those are the things that are also required for CSI incentives for the State of California.

So there's a wonderful program out there, as Pete alluded to, in terms of providing incentives for solar energy adoption, but this is an area where this technology is just now becoming commercial to the point where the standardization of equipment and the certification of that equipment is still being developed.

As that catches up, we'll see some incremental effects.

One of the interesting things that you see in terms of the installed cost range is the installed cost range is actually fairly competitive and roughly, just in terms of kilowatt equivalent, just under $2,000 per kilowatt installed, with a fairly narrow cost range, and that's because a lot of the technology is already well defined.

The issues between small and large go to location and size of solar collector area, and the complexity of the system, and also whether it's an air system or a hydronic or water system.

This is an intriguing technology to us, as we went through the research, because it has an awful lot of potential. It has an awful lot of potential in terms of its applicability and climate protection. It has an awful lot of potential in terms of the future scaling effects of the technology, even though we're not seeing them yet.

And we predict with the growth of this industry in fits and starts, it will take at least five years for this technology to really hit mainstream and when it does we'll start seeing more and more cost effects.

And I'd like to take a moment to explain some of the unique aspects of this technology that could happen in California, where research is going on at a global level.

The really interesting part of this technology is not just solar space and water heating for California. If you think about California's climate, there are unlimited applications for heating. There are lots of applications for cooling. For cooling.

The research that's going on in this technology is, and this is happening both in Germany and in Israel, is integrating solar space, water heating, and cooling, using either one of two types of cooling technologies.

One is desiccant cooling technology and the second is thermal absorber technology, that's currently used on a large scale for utilizing waste heat off of boilers and so forth.

The issue with those technologies right now is that research is only now being done. There are commercial equipments that are available, but not yet commercially viable in terms of the economics. And a lot of the fundamental research that's being done, both in Germany and Israel, around cooling applications is lowering the cost of the thermal cooling circuit, lowering the cost of the desiccant chiller, or the absorber, making them modular, making them plug and play.

When that happens, this technology could be a disruptive influence in terms of its applicability to the State of California, because at that point you've really got a four season solution and one that more closely mirrors the climatic aspects of the State from north to south.

Moving on to another innovative technology that's just not really gaining hold, and we've certainly seen a lot more noise about geothermal heat pumps in the last several years, is this is another technology that really could help in terms of energy efficiency, in terms of demand reduction for electricity demand in the State of California, and could also impact climate change goals over all because of the higher efficiency of the technology.

I like to refer to geothermal heat pumps, basically, as indirect solar. Indirect solar, because what we're using here is we're using the constant temperature of the earth, which is warmed by the sun, as basically a heat source and a heat pump source.

And that constant temperature allows higher efficiency than normal air-based heat pump systems, it's very reliable, and once the first cost is passed, it's much less expensive.

The key overall issues involved with geothermal heat pump design and application are the initial cost and technology involved in installing the ground well field that serves as the heat sink for the heat pump application. That takes land, that takes space, most importantly it takes design and installation.

Here's another example where the discrete nature of utility technologies at utility scale are blurred by the multiple people that it takes to make a community scale technology work.

For example, for the heat pump well field, itself, you need a well driller, you need a certified civil engineer, you may need geotechnical analysis of the field to be able to look at the soil properties of the field, drill the wells in the right amount and the right depth, and then assemble the plumbing and piping circuit for it to all work.

You know, right there just in getting the ground well together three contractors versus one, if you're just installing a conventional heat pump system.

And that's one of the areas in terms of market development that needs to be overcome for the technology.

One of the other issues and specifically to geothermal heat pumps is the geothermal systems are sized specific to the building and the type of use of the building.

A restaurant will have a different thermal use profile than an office building that empties out at 5:30 or 6:00 o'clock every evening. And so the types and usages of the building all have to be considered in the system and our key cost drivers.

Maintenance for geothermal systems is very low. The type of soil, as we've talked about, has a key influence on the size of the field that's used for thermal heat pump. And one of the key issues in terms of managing the long-term reliability of geothermal heat pumps is water scaling, because that can damage the overall system efficiency of the heat pump, itself.

What you see on the left, the picture on the left is a picture of probably the most prevalent type of system that is utilized for community and building scale, and that's a vertical ground bore system.

Residentials tend to use loop systems that are horizontal in character, but for most community scale and building scale systems the vertical ground bore is often the most space efficient.

One of the key issues and I think one of the things that has limited the commercial appeal of geothermal heat pump applications to this point, absent the climate change debate, is that for each system a detailed engineering and economic analysis really has to be done for each site to make it work.

And on the one hand this makes it very palatable for public buildings, for schools, for hospitals, for prisons and so forth, where that can be factored into a new building, but the larger issue from a manufacturer’s stand point, and we’ve talked to several manufacturers is, you know, they sell and support the equipment for geothermal heat pumps, but they don’t necessarily want to be the system integrator because it’s not generally a function of their core business which is in the older technology, air source and other water source heat pumps that are utilized.

So they see it as a cannibalization of their direct sales versus advancing a newer renewable technology, and so there ends up being kind of a conflict in the manufacturing level between the adoption of geothermal heat pumps. They’d rather take that small niche business and leave it to others and that leaves the country and the State of California with a number of very well-meaning and well-skilled small integrators.

When you think about that from a community or building scale perspective as an owner, what that means is you have to make a conscious decision today to implement geothermal technologies even though in the long run they're a lot more cost effective and they're a lot more efficient.

And so today that's one of the reasons why you see the building usages being more in a public domain versus in a private domain, it's just a higher bar that has to be overcome to fill.

One of the key things that we see in terms of long-term cost drivers is right now there isn't enough -- there isn't enough critical mass in terms of scale to drive experience curve effects.

And as we mentioned before, each design tends to be custom tailored to the building and tends to be unique. And so while there are some learnings, without some form of disrupter that we haven't seen yet, we see basically increases that are along the lines of inflation over the period of time.

One of the key things to take a look at in terms of overall energy costs is the roughly $500 a ton year in overall cost, at which typically is 20 to 30 percent lower overall than the cost of conventional heat pump generation.

And now, Pete Baumstark will take a look at the solar water heating residential technology.

MR. BAUMSTARK: Okay, thank you, Chip.

Okay, residential solar hot water pump, there's been a recent legislation in California that resulted in a pilot program in the San Diego area for incentives for solar hot water. You know, the thing with that is, you know, prior to that most of the solar hot water experienced in California was obtained back in the eighties, and with AB 1470 we've seen resurgence in California.

Now, the incentives have gotten extended for that pilot program or the program got extended with increased incentive funding. There is talk that it will become a statewide program and it's unclear at this time whether it will. But, you know, as far as most of the cost data and whatnot, I relied on the solar hot water pilot program from San Diego that would be applicable to California.

Now, there are basically five different types of systems, and depending on the climate zone, depending on the part of the country, some systems will work better than others.

You know, you essentially have a couple types that are direct systems, meaning water comes into the collector from your water service; it goes through the collector, cycles into a tank and is used directly as hot water in a household.

There are other indirect systems where you have a circulating fluid, circulating heat transfer fluid that would heat water in a tank that would go and supplement, for example, a natural gas water heater.

You know, we've seen both types installed under the San Diego program.

Now, one example is like in Hawaii, they almost always have an integrated system where you have -- you have a hot water collector, with a tank that is mounted integral to the collector, that is at a higher elevation and that's a direct system where you essentially heat the water stored in a tank, right at the collector, and use the hot water.

In such a system you don't really -- you use it in warmer climates because you don't really need the freeze protection that in colder climates you would.

And there are other systems, there are glycol systems, there was one system called the drain back system where, essentially, you pump glycol through your collector, it goes into a heat exchanger in your tank, heats the water, then when the sun goes down all the glycol just drains back into your storage tank. And, you know, that is one method of freeze protection that is useful mainly in the northern climates or colder climates.

Now, if you look at the ratio of systems installed under the San Diego pilot program, it's about 50/50. You know, you have about 50 percent glycol type systems, 50 percent are without, you know, with an integrated collector and storage system.

Now, some of the cost drivers is -- probably the main cost driver would be the equipment costs. Now, typically, the collectors you see, you know, they include a lot of aluminum, a lot of copper, a lot of heat transfer elements, and with commodity costs, you know, those are -- that basically, mainly drives the cost.

Other things that could alleviate the cost are State incentive programs and whatnot, which we have as a pilot now, could become statewide.

Now, this is my cost trajectory. Now, there has been some R&D funding applied to these technologies from the DOE, with the goal of reducing the installed costs by about 50 percent.

As I touched on previously, there are systems in Hawaii that you don't have to worry a lot about freeze protection, and those are typically less expensive than the ones we've been seeing in California.

Then there are other systems that are installed in Oregon, under their incentive program, and those are typically more. You know, those are typically more expensive, they're about -- it's about a thousand dollars per household system either way, warm climate a thousand less, cold climate a thousand more than what we see on average in California.

The goal of the R&D funding, and there are at least a couple of manufacturers that have products from this funding, but the goal is to reduce the cost, primarily to be able to use plastics instead of copper or aluminum, as far as your collector goes.

We haven't seen as of yet any of these collectors installed under the San Diego hot water pilot program but, like I say, there are a couple manufacturers that have the products designed.

So I foresee the cost trajectory to be, you know, pretty flat over the next few years. And as more lower cost systems come in play, assuming the hot water incentive program becomes a statewide incentive program, I'm foreseeing in a few years the costs essentially drop for the curve.

Okay, so that's it for our technology. I'm going to open the floor to questions.

COMMISSIONER BYRON: Do you have any specific questions, Commissioner?

COMMISSIONER BOYD: I don't think at this moment.

COMMISSIONER BYRON: You know, it's a very good overview, a lot of detail around some promising and maybe what seem to be esoteric generation techniques. I'm reminded of some others as you're going through these presentations as well, that I'm tempted to share with you just to see if you've ever heard of them.

But it is informative, but I don't think either of us -- maybe Commissioner Boyd may, but I don't have any specific questions to ask you, but it's a good thorough analysis, and it's exactly what we're looking for in this kind of cost comparison or cost analysis here.

There may be questions from others in the audience and if there's none specific on this topic -- I should ask it positively, any questions?

And we're going to open it back up to general comment again, is that correct, Ms. Green? Okay.

Commissioner Boyd, did you have any questions?

COMMISSIONER BOYD: No. No, thank you. But thanks for the presentation, I've got lots of notes, but they're not questions.

MR. O'DONNELL: Thank you Commissioners, thank you.

COMMISSIONER BYRON: All right, well there's a fair amount of time here for public discussion and comment.

Mr. Alvarado is coming up to the microphone to lead that discussion, I take it.

MR. ALVARADO: Well, just break this open to any comments. I see we have one taker.

MR. CAMPBELL: Matt Campbell, from SunPower, again.

Commissioner Byron, I just wanted to respond to your question, a very good question on land use and putting the ground-based photovoltaics close to load or population centers.

So what we see in California and in other states is there is a big desire to do sort of small systems, say 500 kilowatts to a couple of megawatts close to load. I think a lot of the --

COMMISSIONER BYRON: Was I in the ballpark on the acreage for that sort of thing?

MR. CAMPBELL: Yeah, so the acreage is a complicated question, it depends on the panel and it depends on how closely you space them, and the spacing is discretionary. So the further they're spaced out, the higher the capacity factor. The closer you put them together you lose some output, but you gain efficiency in the land use.

So I'd say that it could be four acres per megawatt for a good case, with a high efficiency panel. It could be six acres per megawatt for more of a generic or kind of a standard technology. But I'd say four to eight or nine is a good range.

And so, well, I'll give you an example, we're doing a ten-megawatt in Chicago right now, and that's right in an urban area, it's on a brown field, and one of the things that's common is a desire to site on brown fields or landfills in the quasi-urban areas.

And in that case we fit ten megawatts on about maybe 60 acres, but we really packed it in because the land was constrained.

But we do see, in the case of people like water districts, they may have unused land on the periphery of their facility and that they -- you know, they need buffer and so the buffer's not doing anything so they can put PV on it.

So it is a concern, but we do see opportunities to build it closer to load.

COMMISSIONER BYRON: Good.

MR. CAMPBELL: Thank you.

COMMISSIONER BYRON: Thank you.

MR. MURRAY: Hello, my name's Richard Murray, I am a landscape architect from Monterey, and I am kind of a duck out of water in a lot of the comments this morning, but this afternoon has been much more close to where my concerns are.

I think that the way that I've gotten started in this, I just wanted to try to put in a simple system on a piece of land, when I could sell the electricity back to the utilities and use the money for nonprofit activity.

COMMISSIONER BYRON: If it were only that simple, huh?

MR. MURRAY: If it were only that simple? And so I go there and I ask the question and they give me the contract and the market price reference, and you go to figure it out and, gee, it doesn’t work. And so then you start to get into it a little deeper and deeper, and so here we are.

I think that the issue, in a couple ways, there is just an amazing amount of built facilities in the State that could be retrofitted for photovoltaics. Any time you fly into any metropolitan area you see countless rooftops, flat, nearly so, that are all available, you know, or could be, or a lot of them could be.

It depends on the incentives to develop the project and to develop the initiative for it.

There is countless amounts of people, similar to myself, who have had photovoltaics for heat generating; the last comments were on solar hot water and heating of air. I put it in my house in 1980, in my office building in ’85, and heat the air as well as the hot water, and you find that it’s more cost effective in a residential unit than it is in commercial, because in commercial you aren’t using the hot water effectively in the evening because that’s when you leave and go home, and the building doesn't need to stay hot, it can cool off.

So you lose the heat therms that you generate in the daytime that you could use in the evening at home in the hot water, dishwasher, or the laundry, so it's not nearly as effective in comparison with residential use, or at least that's what we found.

The issue on photovoltaics, though, I think that there is a great amount of people that would get a lot more value out of trying to invest their savings or money, if they knew they had a return of some kind on the product at the end. You know, whether it's a retirement agency groups, or teacher savings programs, or whatever, if there was a -- if you could invest it in the utilities, they would try to use that money in a similar manner.

There is a lot of farmers that would put out their lesser valuable acres into putting it into photovoltaics, if they need that they had -- if they could make as much as they make doing farming on it. And I'm quite sure that that is easily documentable, it's just a matter of trying to figure it out.

There's an awful lot of other areas where you could wind up -- the more that energy is decentralized, the less that you lose from transmission and we all know that transmission is a big loss in all of our electrical systems, wherever they are.

And with all of the new facilities that are being generated, you have to go in with these large facilities, put in new large transmission program or facilities for it, and if you didn't have -- if you could set it up so there was more smaller units spread across the State, you'd have a less -- you could use the infrastructure that you already have existing to more effective use.

And so those are some of the answers that I had on that end.

I had another issue or in one of my things I got a PUC Commission analysis for the last 32 years of history, and prices of electricity has gone up 6.2, 7.1, and 8 percent, depending on whether it's residential or commercial.

And I noticed that in the price marketing index we are looking at something in the order of half again as much increase for the market index for the next ten years is five cents greater, and on the PUC's index it is 20 cents.

So it's -- there's a lot of areas where you could wind up, I think, making a greater impact if you could figure out the way of getting the general public to participate more fully in the energy issue.

Thank you.

COMMISSIONER BYRON: Thank you, sir, and thank you for being here today.

Be careful, you know, you get into this and you might get hooked in terms of all the issues that we're dealing with.

I'd like to particularly just address, briefly, your -- I saw your letter to this Commission back in July, I just saw it in the back of my binder here, with regard to the photovoltaic project that you're interested in. And I'm glad to see that you are interested in the feed-in tariff issues that we are working on here in this Commission, and at the State, and there's some legislation pending around this.

But as you may have found through your studies, there's a little bit of resistance in some of the service territories of utilities in the State to feed-in tariff and having generation that's in their service territories.

Also, you had mentioned the farmland and, of course, if you're familiar with the Williamson Act, there are laws that prevent farmland for being used for other purposes than farming.

So we have a few impediments that we have to overcome in order to enable you, and you said the many others that are interested in doing these kinds of projects, and we're trying to figure that out.

Did you want to comment on something else? You started to get up like you were going to comment and I -- so, you know, my conclusion is thank you, and I hope you will stay engaged and interested, and I hope you will continue to work on these projects.

MR. MURRAY: Well, I'm a planter by profession and so the farmland, the Williamson Act issue, it depends on what you are claiming as being farming activity, and then the product, the farming ability of the soil that's being used.

And there's a variety of things that can influence whether the land is actually good enough to do particular farming on or whether it's subject to flooding, and in case of certain crops, there's a whole group of ways of getting around different issues.

COMMISSIONER BYRON: Thank you, sir.

COMMISSIONER BOYD: Yeah, thank you, Mr. Murray. I'd seen your letter before and as indicated, we have it here.

Also, I was going to say it to Commissioner Byron, but he got the point that I believe you had a candidate to sign your petition for feed-in tariff of Commissioner Byron.

COMMISSIONER BYRON: Well, of course, feed-in tariffs have been put forward as a recommendation by this Commission I believe long before I got here.

COMMISSIONER BOYD: True.

COMMISSIONER BYRON: So it certainly has been on our radar screen for a while. But that's good and bad, I suppose, we haven't made as much progress as we wanted to at this point, but we are making progress.

COMMISSIONER BOYD: The Spanish haven't done us any favors, I noticed.

MR. ALVARADO: Any other comments or questions from the audience?

MS. GREEN: Commissioners, we don't have any questions from the WebEx participants who are logged in, but I would like to open the phone lines and give them a chance, if the callers have any questions.

COMMISSIONER BYRON: So we're opening, we're unmuting the phone lines, so if you're on a line and you have a question or comment, now would be the time to speak up.

MS. HARRIS-HICKS: May I speak up now.

COMMISSIONER BYRON: Please go ahead.

MS. HARRIS-HICKS: How do we -- how do we speak up?

COMMISSIONER BOYD: We can hear you now.

COMMISSIONER BYRON: We can hear you. Please identify yourself.

MS. HARRIS-HICKS: I'm Lynn Harris-Hicks and I'm an advocate for a group called CREED, Coalition for

Responsible and Ethical Environmental Decisions, in Southern California, and use as our liaison for different organizations.

And I have been battering the COX (phonetic) generators that they asked for on the -- but I'm not going to try to go into all of that now, but I did want to comment on one of the comments that was put in here, and that has to do with --

(WebEx Interference.)

COMMISSIONER BYRON: Ms. Hicks, hang on one moment. Would other people on the phone line please go on mute. If you're going to speak in the background, because all the lines are open, we need to ask you to mute your phone.

Please go ahead, Ms. Hicks.

MS. HARRIS-HICKS: All right. We are requesting that you use, as much as you can, the actual --

COMMISSIONER BYRON: You'll have to go ahead and speak over that person.

MS. HARRIS-HICKS: What was that?

MS. GREEN: We're just going to mute everybody and then we'll just -- mute everybody and then unmute Ms. Hicks.

COMMISSIONER BYRON: One moment, Ms. Hicks.

MS. GREEN: Go ahead, Ms. Hicks.

MS. HARRIS-HICKS: We would like to request that you gather as many of the actuals of costs, as from our experience record, from the history as you can, rather than depending on the speculative aspects.

And our particular focus right now is on the renewables and energy programs, efficiency program, which is our State plan.

Because we are rather distressed that we have been advocating the transition to renewables now, our organization has for about 28, 29 years, and the State has been making that transition, supposedly, for almost that long. But our State action plan for energy has called for the acquisition of the energy efficiency programs and the energy from the renewables distributed, and I notice that you're not using the word "distributed" and I think that's a good idea because most people don't know what it means.

But designating the building and the community, and the solar, and then some of the other renewables, too, is very good, I think.

And I would like it if you could get your press corp to send out news releases about some of these things because people just don't know -- when I say people, I mean the average person or organization, and so forth, really don't have an access to all this wonderful information that you've given out today, for example, so that's a request.

Now, the business about the actuals is important because we have been, for a long time we were supporting the San Diego Gas and Electric's Fast Track to Renewables, which would have brought the renewables into our area by now, because they were contracting for renewables at such a pace that at the end of 2005, when the energy -- when the Energy Commission -- or the California Public Utilities Commission gave the blank check to Edison for the renewables down here at San Onofre -- I don't mean that, I mean the nuclear down here at San Onofre.

Told them that they could charge to the ratepayers everything that they put in to the rebuilding of San Onofre. Well, they changed that on San Diego Gas and Electric, somebody did, and told them we had to have our share of this pie and stop pushing to get the big steam generators, and that's what it's been called, is replace some of the steam generators.

And we misjudged Edison and that because we found that that meant that they were just calling it steam generation replacement when they were really replacing the plant.

And we only found out, and I put things together and found this out, the different parts of the puzzle, that it's not a replacement of this, it's an end run around the law that says we don't have anymore in California. It's the way they proceed.

Because three years back, when the Nuclear Regulatory Commission was having a public appearance telling about the safety at San Onofre, and when we finished with the session one of the head persons said, well, that's just the way we do, and he's talking about the replacement.

And then there was an official, who spoke to a group that was before our San Clemente Green here, and when we asked him to tell us about what they were doing there and why they're doing the rebuild things, and so forth, instead of investing in the renewables and the solar, that we were interested in, he said -- he explained to us that when they have an outage, I guess that's about every 18 months, they had an average for refueling, that they bring in a thousand men and they put -- replace a thousand valves.

And I didn't connect it, I didn't connect it at that time, but a couple of weeks ago I realized that nuclear energy, generation of nuclear energy is so violent, is so degrading, so destructive that we are looking at not a matter of whether, and going through this that we're paying twice for what we were promised for 40 years, but we're looking at a situation where we are in continual replacement, continual.

COMMISSIONER BYRON: Ms. Hicks, could I ask you if you could bring to a conclusion the point you're trying to make?

MS. HARRIS-HICKS: All right. I want you to reassess, from the stand point of usage, take the cost of building the plant and then you consider that 40 years in your comparison. For the solar on my roof, I think they would consider that one 20 years, because we haven’t had the experience, but we haven’t had the experience with the nuclear, either.

And so I think that this is the time to validate your assessment, because you should be doing, as the leading authority in our area has asked, the California Public Utilities Commission, an independent audit of all of their calculations, all of their expenditures, and so forth.

Because what we are looking at is a -- this cost of war, when we talk about continual war, a constant war economy, they are in a constant replacement economy.

And so it may have been that they replaced everything on --

COMMISSIONER BYRON: Ms. Hicks, this is Commissioner Byron.

MS. HARRIS-HICKS: What?

COMMISSIONER BYRON: Ms. Hicks, can you hear me?

MS. HARRIS-HICKS: Yes.

COMMISSIONER BYRON: I’m a little bit concerned that you are maybe misunderstanding the purpose of our workshop here today, and I can appreciate that you have some concerns about the costs of the nuclear plant, San Onofre, but that's really not what we're discussing here today.

So I'm going to go ahead and move onto the next commenter at this point, unless you have something else you want to add to the cost of generation.

MS. HARRIS-HICKS: Well, I'd just ask that you revise your estimate of the various ones, not just there at the solar, but all of them from the stand point of the length of time that those expenditures are used. The length of time would be variable.

And in this case we know that they had to replace the rolls on the San Onofre containment there seven times on the unit one. And you have the actuals because that unit one is finished, now, and so you have the actuals on that, and you have the actuals on Finland, where they're putting in one of the new generation. You've chosen a west account one thousand there, but I don't know what it is in Finland, but it would be similar, probably.

COMMISSIONER BYRON: Okay, Ms. Hicks, thank you very much for your comment. We're going to take your comment and we're going to move onto the next one.

MS. HARRIS-HICKS: Thank you very much.

MS. GREEN: So we'd like to unmute the phone lines again, to give the others an opportunity. Go ahead.

COMMISSIONER BYRON: Ms. Green, I'm not sure about this unmuting. Is there a way we can ask them to raise their hands on WebEx?

MS. GREEN: No, there's no way because they're called in.

COMMISSIONER BYRON: I see.

MS. GREEN: And that's WebEx.

COMMISSIONER BYRON: I see. All right, last chance for any of those who called in for public comments.

MS. GREEN: I think no one's speaking.

COMMISSIONER BYRON: All right, thank you very much. You may mute them.

MR. ALVARADO: Well, in closing, I just want to remind folks that we still have an open comment period, that we will be receiving any comments to our work by five o'clock, September 2nd. And any of these comments we do receive will be considered for any further adjustments in preparation of our final staff report.

COMMISSIONER BYRON: Do you have a date or a deadline, did I miss it when you said it?

MR. ALVARADO: September 2nd, five o'clock that night -- in the afternoon.

COMMISSIONER BYRON: Yes, we'd appreciate you adhering to the comment period if at all possible, staff is under a difficult deadline to try and complete all of their work, not on just this topic, but all of the topics that input to the Integrated Energy Policy Report, so I hope that helps.

MR. ALVARADO: Same here.

COMMISSIONER BYRON: Anything else, Mr. Alvarado?

MR. ALVARADO: No, I think that's it. I think this is just a summary of really a long effort that's been going on for this past half-year, with some excellent contributions by the project team.

COMMISSIONER BOYD: I just want to thank the project team, as you labeled it, for the hard work. As I said, this was extremely interesting reading. And when I said laborious, I just meant very complex, technical, and what have you, and a person had to read it carefully. I didn't mean that it was an unwanted chore, let's say.

And I thank everybody for their testimony today; this is proving to be, I think, quite helpful to us in formulating the 2009 IEPR comments in this area.

COMMISSIONER BYRON: Thank you, Commissioner.

My read on all of this is I think the staff's done a very good job of incorporating recommendations from previous IEPR; a lot of effort has gone into being as thorough and as accurate as we can in making comparative costs for all these different generation technologies.

I notice the number of generation technologies seems to keep getting bigger, not smaller.

But I’m also reminded, this is a catch up, we’re constantly trying to play catch up as technology emerges. We’ve heard from commenters today how policies change, opportunities for the technologies change, and trying to keep up is very difficult.

I liked the comment, instead of doing this every two years, let’s do this continuously. Of course, but I guess that does assume to some extent we have an unlimited amount of staff and resources to be able to apply to these issues.

I’m also reminded that the cost of generation stuff, material has many different uses, it informs policy makers, but as I can tell from the commenters here, today, folks use it and interpret it in different ways. And fair enough to say there’s just different purposes in having these absolute and relative comparisons on costs.

It’s extremely helpful; it informs so much of what we do in this State around energy policy.

As I was listening here today, I thought of a -- I guess I jotted them down as random thoughts, but I hope you’ll see the connection that they really do come back to the cost of generation.

I’m reminded that there’s other factors that often drive a project or a project being developed, not just cost. And we’ve heard about some of those examples here, today.

I was struck by the one that Mr. O'Donnell indicated, $23 million per million BTU. I mean, who would ever consider paying those kinds of costs? You know, even -- there's even an electric rate chart published for the space station, if you have projects that you're doing up there.

The reality is that we're oftentimes willing to pay more for things. My watch battery, I hate to think how many tens of thousands of dollars of kilowatt hours that cost is, but I'm certainly willing to pay for it.

But there are other factors that come into place, social benefits, et cetera, that we need to factor into all of this, and maybe that's why we're hung up on feed-in tariffs.

COMMISSIONER BOYD: Don't get me going on watch batteries. The one that comes with the watch might go eight years; the next ones can't make it through a year before your jeweler needs to replace it.

COMMISSIONER BYRON: Well, and so that energy storage issue, I think is going to be probably the next area that we're going to ask you to look into, because that's what's going to begin to free up some of the renewables that we're looking at, and increase the -- let's say the value of the attributes associated with renewables.

The other is this notion of some projects being affected by market risks and regulatory uncertainty. If only generation technologies were selected on the basis of costs, again, but they're not, there are environmental and health impact issues.

And I would argue that these market risks that came up earlier today aren't necessarily -- well, let's just say I'd argue that they're really regulatory uncertainty, that the more that, as policy makers, that we can provide some certainty around this, issues like feed-in tariff, again, I think we would see some of these generation technologies move forward more.

And finally, Commissioner, I don't know if you know this, but today marks the first day that this building is on a new cooling and heating system. I understand that our central plant converted last night, and this building and 21 other buildings are being cooled and heated by a new central plant, much more efficient, using a lot less water.

But unfortunately, a couple of years ago, we couldn't convince them to put in combined heat and power. Maybe if we'd had more accurate costing information, like this, and presented it to the State at that time.

Actually, I know the problem; the problem is that the capital costs is what kept that one back.

And so if you'll forgive all these little random thoughts around this issue, cost of generation's extremely important, it informs us, but it's not the only issue that's affecting whether or not these projects can go forward.

We're interested in seeking entrepreneurial projects, like Mr. Murray's, and others as he's indicated, have a place. The notion of seeing private capital come forward in the generation market, providing the right incentives for renewables, certainly important policies of this Commission and this State.

I think I've rambled on long enough. I'd like to thank the staff, and for all of you that were in attendance here today, and those on the phone, very informative, and I think it helps us make some very valuable recommendations. I hope they'll be valuable recommendations in this year's Integrated Energy Policy Report.

Thank you, we'll be adjourned.

(Whereupon, at 2:45 p.m., the Committee Workshop was concluded.)

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REPORTER'S CERTIFICATE

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, an electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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

IN WITNESS WHEREOF,

I have hereunto set my hand this 14th day of September, 2009.

Barbara Little