BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the matter of,)
)
IEPR Lead Commissioner Workshop)Docket No. 12-IEP-1D
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Combined Heat and Power to Support
California's AB 32 Climate Change Scoping Plan

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

THURSDAY, FEBRUARY 16, 2012
9:00 A.M.

Reported by:
Kent Odell

COMMISSIONERS:

Robert Weisenmiller, Chair
Carla Peterman, IEPR Lead Commissioner (Absent)

STAFF:

Suzanne Korosec, IEPR Lead
Bryan Neff
David Vidaver
Rinaldo Aldas, PIER
Jim Bartridge

Also Present: (* Via WebEx)

Cliff Rechtschaffen, California Office of the Governor
Sam Ruark, Sonoma County
John Hake, EBMUD Energy
Bill Martini, Tecogen
Joe Allen, Solar Turbines
Ken Darrow, ICF International
Barbara Barkovich, California Large Energy Consumers Assn.
Tom Silva, representing Chevron
Tom Casten, ACORE Board member, Recycled Energy Development
*John Ballam, Massachusetts Department of Energy Resources
Keith Davidson, DE Solutions
Brandon Blizman, Makel Engineering, Inc.
Jennifer Kalafut, California Public Utilities Commission
Michael Alcantar, Cogeneration Association of California
Ray Williams, Pacific Gas & Electric
Gerome Torribio, Southern California Edison
George Simons, Itron
Dave Barker, San Diego Gas & Electric
Ray Pingle, Sierra Club
Andy Schwartz, California Public Utilities Commission
Justin Kubbasek
Tim Tutt, SMUD
Evelyn Kahl
Dennis Peters, CAISO
Andy Brown, Ellison, Schneider & Harris
Brian Biering, Ellison, Schneider & Harris
Beth Vaughan, California Cogeneration Council
Greg Wolf, NextEra Energy
*David Erickson

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P R O C E E D I N G S

FEBRUARY 16, 2012 9:00 A.M.

MS. KOROSEC: All right, good morning everyone. I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit, and welcome to today's workshop on the Combined Heat and Power in California.

A couple of housekeeping items before we get started. Restrooms are in the atrium out the double doors and to your left. We have a snack room at the top of the stairs in the atrium on the second floor under the white awning. And if there is an emergency and we need to evacuate the building, please follow the staff out the door to the park that is kitty corner to the building.

Today's workshop is being broadcast through our WebEx Conferencing System and parties do need to be aware that you're being recorded. We'll make an audio recording available on our website a couple of days after the workshop, and then we'll provide a written transcript in about two weeks.

We do have a full agenda today and Brian will go over that in a moment, but I do want to mention that there is a general public comment period at the very end of today's workshop, and during that period we'll take comments first from those of you here in the room, and then from those participating via WebEx. When you're making comments or when you're asking questions during the day, please come up to one of the microphones so that we can make sure we capture your comments in the transcript, and so that the WebEx folks can hear you. And it's also helpful if you can give our transcriber your business cards so we make sure that your name and affiliation are spelled correctly in the transcript.

For WebEx participants, you can use either the chat or raised hand functions to let our WebEx Coordinator know that you'd like to make a comment, and we'll either relay your question or we'll open your line at the appropriate time.

We're also accepting written comments on today's topics until close of business March 9th, and the Notice for today's workshop, which is available on the table in the foyer and also on our website, describes the process for submitting comments to the IEPR Docket.

As I said, we do have a full agenda, I won't take up much more of your time, but I do want to provide just some brief context for how today's workshop fits in within the Integrate Energy Policy Report Proceeding. The Energy Commission prepares an IEPR every two years with assessments of energy supply, demand, price, transmission, distribution, and market trends that are then used to develop recommendations to the Governor for California's Energy policies.

The 2011 IEPR was approved by the Commission last week and one of the areas identified as needing further analysis in both the 2012 IEPR Update and the 2013 IEPR is the important contribution of CHP to California's Clean Energy Goals, as well as Governor Brown's Clean Energy Jobs Plan goal of adding 6,500 megawatts of new CHP by 2020.

The 2011 IEPR emphasized the need for the Energy Commission to update past assessments of CHP potential and to develop forecasting methods and scenarios that more accurately account for the potential contribution of CHP to California's energy mix. The discussions and feedback from today's workshop will feed into that, efforts to better reflect CHP goals in our electricity and natural gas demand forecast, and will also influence our analysis of electricity infrastructure that is needed to satisfy future demand, maintain reliability, and achieve our clean energy goals.

So with that, I'll turn it over to the dais for opening remarks.

CHAIRMAN WEISENMILLER: Thank you, Suzanne. First I would note that Commissioner Peterman is sick this morning, so Jim Bartridge will be sitting in for her.

Certainly, this is a workshop she's been looking forward to, so we both regret she's not here today, but I am sure Jim will sort of fill her in and will probably have a few words in a second.

As Suzanne said, last year's focus was really on renewable DG and this year was turning attention more to CHP, or Cogeneration, or recycled power. And I think everyone knows that energy efficiency is really at the top of the loading order in California, and oftentimes we think of energy efficiency in the sense of buildings and appliances, making those more efficient. But certainly, cogeneration has always been a key way to basically have a much more efficient industrial system. And when I first came to the Energy Commission in '77-'82, I was responsible for the getting the State's programs in Cogeneration set up. And I remember at that time, at least once a month the then Chairman of the Energy Commission, Richard Mullen, would call me in and say he had gotten a call from the Governor wanting to know what have we done on cogen, why wasn't there any action or progress there. And every month, I continued to scramble and I guess, as we're now --

MR. RECHTSCHAFFEN: [Phone ringing] He's calling right now.

CHAIRMAN WEISENMILLER: Probably is -- so this remains -- this was and certainly remains a very high priority for the Governor. I think Cliff's presence here sort of symbolizes that, and certainly a very high priority for me.

I think in that time we made a lot of progress and I want to really tip my hat in part to the leadership, then, of not just the Governor, but certainly Commissioner Detrich at the PUC was really a leader there, Commissioner Reed here, Suzanne Reed was a leader, and Mary Nichols of the ARB was very much a leader in that area. And certainly one of the other inspirations certainly in OII 26 for those of you who weren't there, certainly, there is a great book by David Roe, Dynamos and Virgins, that went through that series. But the Environmental Defense Fund particularly was very instrumental in the State's cogeneration push; Tom Graff certainly took a very visionary role on that.

And certainly we got things moving, and one of the ways we did that, again at that point, as sometimes now we have the utilities policy and cogen, is just to say no, and that's not acceptable. And certainly, we're looking for creativity to try to move forward. At that point, obviously, one of the ways the PUC got the utilities' attention was PG&E was fined for inadequate progress on cogen. And I think, again, that's a symbol of that, the

State takes these goals very seriously. So with that, do you have any words?

MR. RECHTSCHAFFEN: Thanks very much, Chair Weisenmiller. As Bob said, this is a priority for the Governor. He has said, "By installing equipment to produce electricity from heat now wasted, industries can reduce overall fuel use and drastically decrease energy costs." Now, he said that in 1981 and it wasn't called Combined Heat and Power then, it was Cogeneration, and Chair Weisenmiller had a lot fewer gray hairs, but he was instrumental in setting the policy then. And Governor Brown has been a leader in developing this technology since his first Administration.

We made a lot of progress back in the 1980's and 1990's. We have 8,500 megawatts here, we'll talk a lot about that. We are second to Texas and Governor Brown doesn't like being second to Texas in anything, let alone in the clean energy field. I don't know if we can catch Texas given all of their oil and gas operations, and we're probably half of where they are. But we've done a lot less since the '80s and '90s, and we need to do more. We need to do more for lots of reasons, as Bob mentioned. We need to do more to reach our efficiency goals, we need to do more to reach our greenhouse gas goals, this is a major part of the AB 32 Scoping Plan, and we need to do more to help us meet load in constrained areas, and to save money, to save energy costs in an era of rising costs. The Governor is firmly committed to doing this, he doesn't call us once a week about this, but he may once we start getting going, he has a clean energy plan that he outlined in the campaign to call for 6,500 megawatts of new generation by 2030, and he's firmly committed to putting us on a path to get there, and this is the start of a process that the Administration is going to be focused on to figure out the best strategies that we all collectively can work on to get there, not just the Energy Commission, but the Public Utilities Commission, the ISO, the Air Board, and other agencies.

We've made some landmark progress recently with the QF Settlement, with the implementation of the feed in tariff for small operations, but there are lots of regulatory challenges that remain, market challenges and others. I look forward to the rest of today's workshop to hear about not just the potential or the challenges, but strategies that people can suggest for moving forward and achieving these important goals. Thanks very much.

MR. BARTRIDGE: Good morning. I will just say Commissioner Peterman sends her regards today and apologizes that she couldn't be with us. She sees cogen as an important part of meeting the State's energy Policy goals and looks forward to further understanding the technical and market potential of new cogen, as well as what we can do to remove market barriers to new CHP.

MR. NEFF: Wonderful. I'm Bryan Neff. I work in the Electricity Analysis Office, and first I'd like to thank everybody for coming today. It's an important day and hope to get a lot out of it.

So everybody and many of us show up every day working towards California's goals and, just as the Commissioners have talked about, they're very lofty and we hope to get there. And part of what we're doing to try and get there is, today, to build the public record that will be used in the 2012 Integrated Energy Policy Report and the other documents that the Energy Commission creates, and will focus on what it's going to take and what are the implications of reaching those goals.

So today we're going to be starting with the ICF Report and its state of the possible future development of CHP and existing State policies, the prospective development that will occur from that, and then provide a technical analysis based on a pricing model, and gives the context for existing and potential CHP State Policies. It provides megawatt forecasts that can be used as guideposts, providing context with which to evaluate potential policy actions.

Following that is a small CHP Market Panel, it's made up of Project Managers and CHP Manufacturers. The Project Managers will be presenting on their experiences with specific projects they have worked on or are currently working on, presenting the difficulties they encountered, but did not stop them, but may have stopped many others. We also hear from Technology Manufacturers who have developed and manufactured their technology in California, yet have been less successful in selling it here.

Later, we will hear about Industrial CHP issues. Although these projects usually fall in the size range of the small CHP market, their experiences spread over the entire industry and effect policies that have widespread impact.

In the afternoon, we'll be hearing some innovative ideas for CHP Financing, some of the novel ways that make CHP projects viable based on its operating characteristics, as well as about the approach in another state, what Massachusetts has done to level the playing field for the various technologies that provide energy efficiency and greenhouse gas savings.

After that, we're going to focus on Research and Development that has always played a role in helping the state meet its goals, and for CHP it's no different. We will hear from the Commission's PIER Program about the current work that's being done to meet some of these existing barriers and overcome some regulatory hurdles.

And finally, we'll shift our attention to the impact CHP development will have on infrastructure planning. The three investor-owned utilities play a major role in development and we also hear from them, as well as from the CPUC and developers who also sit at the table.

We have a busy day, so in getting started, I'm going to now introduce Ken Darrow, who is a Senior Technical Specialist at ICF. He is responsible for economic, market, and strategic analyses for energy technologies and markets. Mr. Darrow has over 30 years of experience evaluating energy technologies and markets, conducting regulatory analysis, and managing international technology transfer and market transformation. He has contributed to numerous Distributed Generation studies, technology specific assessment of advanced distributed generation technologies, and their application, and application focus studies such as the assessment of CHP market opportunities, including the 2005 California Market Assessment Report and the 2009 California CHP Market Assessment Report Update.

MR. DARROW: Thank you, Bryan. Good morning, Commissioners and good morning to all of you. As Bryan mentioned, I'm going to talk about the work that we just completed on a revised Combined Heat and Power Market Assessment. Another member of our team is here today, Eric Wong, has been active for a long time in the California CHP business, and he led the policy analysis, and if he could just wave in the back if anyone has any policy specific questions, or if I fall down and need to be bailed out, he's here to take over.

So I have a lot of material, some of it is fairly dry and boring, but I want to try to go through it intelligibly, yet fairly quickly. So the first part of the discussion is on the Market Characterization that we did looking at the policies that effect CHP, identifying and categorizing and quantifying existing CHP, determining what business facilities in California have the potential to add new CHP, and evaluating the electric and gas prices today and in the future, and looking at the CHP technology cost and performance. And all of those assumptions go into the basic economic equation for whether CHP gets adopted or not.

And then the second half, I'm going to talk specifically about how we treated some of the policy assumptions in our scenario analysis, and then present the results of three cases that we ran, a base case, a medium, and a high case, and look at the greenhouse gas emissions implications, and then provide some conclusions from the work.

I've been asked to maybe open up a couple of times for questions, so I think after we complete the Market Characterization, if there are any questions, of course, I welcome the Commissioners to interrupt me at any time with questions. So let's just move forward, then.

The first topic we're looking at is the Policy Landscape. I talk about all of these policies later in specifics as to how they're modeled, so rather than go through all the detail that is on the slide, I'll just mention that we looked at, in terms of the QF Settlement Agreement and the AB 1613 Export Feed In Tariff for CHP systems less than 20 megawatts, the expanded Self Generation Incentive Program, and the Renewable Portfolio Standard, which doesn't directly affect CHP, but affects it indirectly, and cap-and-trade, which is the same thing, there's an indirect effect on CHP from cap-and-trade. And then, also, the issues of the Distribution System Interconnection Settlement Agreement.

Certainly, for the first five of these on the list, they're all explicitly modeled in the work that we did and I'll explain that as we move on.

The first area of analysis on Existing CHP shows the ICF keeps what is called the ICF CHP Installation

Database nationally of U.S., and in California we estimate that there's 1,200 CHP sites producing 8,518 MW of power. One of our functions on this project was to reconcile some differences in our database with numbers that the Energy Commission has and that the CPUC had, and we were given access to some of the confidential data sources, and went through and verified and compared, and while there are still differences in coverage and definition on certain sites, and inclusion of sites, we feel that we have a good number for moving forward. The details of the reconciliation will be in the report when it's released.

Just focusing on the pie chart here of the CHP that's here, about half of it is in the industrial sector, and about a third is in enhanced oil recovery, the red pie slice. And then about less than a quarter, the remaining, is in mostly commercial which includes institutional and government, and a small amount in other.

I don't show a split in size, but I was asked to talk about it, so the breakdown by size, actually 85 percent of this total capacity is in 112 sites that are larger than 20 MW, and a lot of the sites are significantly larger than 20 MW. So nine percent of the sites produce 85 percent of the capacity. And the small market which is indicated in the bullets there, of 1,282 MW at 1,090 sites. So 91 percent of the sites produce 15 percent of the -- or account for 15 percent of the capacity.

And while it is true that Texas leads the country in total existing CHP capacity, very very little of that capacity in Texas is in what you would call distributed generation. And I think California leads the nation, by far, in terms of the development of the distribution generation side of the CHP market.

The next thing I wanted to look at on existing CHP is the distribution by utility. Over half of the existing capacity is in PG&E territory. PG&E is blessed with a lot of applications that are very CHP favorable. I don't know if they feel it's a blessing all the time, but they have two-thirds of the enhanced oil recovery capacity in their territory and, by far, they have five times the food processing facilities that are in the southern part of the state.

They also have most of the paper mills and they're roughly equal in refining capacity between north and south, but they also lead in CHP and education facilities and, in the very last super large CHP plant that was built in 2001 is in their territory, attached to a steel mill. So they have specific markets and environment unique to the northern part of the state that reflect their dominance in this number.

So moving on from the existing CHP, I want to briefly describe how we calculate the future technical potential. We evaluate markets that have a good electric load factor and thermal loads that could technically support a CHP system with a high load factor and high thermal utilization. And those types of industries are the large process industries, many of which already have CHP, the enhanced oil recovery market, large and medium commercial and institutional establishments, education, health care, hotels. And the report will have a complete list of the sectors that we analyzed. We also specifically look at markets where we're using a portion of the thermal energy to replace electric air-conditioning, markets like office buildings and retail and expanding the potential market for CHP that way.

So based on all those applications, we identify the active sites in the state using the Dunn & Bradstreet database; there is not energy information in that database, but based on other work that we've done that relate energy use to business activity, we estimate electric and thermal loads for each application in each site. And that results in the total technical potential, and from that we subtract the existing CHP to get the remaining potential that can compete for new market share.

So there's a lot more to it than that and those details will be in the report.

The summary of the CHP technical potential is shown on this slide by size. These five sizes across the top of the table reflect the five size bins that we analyze in the model, and there's a total of close to 16 gigawatts of remaining technical potential and about a third of that is in export potential, and two-thirds of that is for electricity that would be used by the facility itself, onsite.

There are some other things I want to point out on this slide, is that if you look again at these big market systems, and there really are essentially two CHP markets in California, for large systems and for distributed systems, and if you look at the over 20 MW size, 80 percent of that market potential is in the export market. So export is a much more important driver for large systems than it is for small systems. And if you look at the export potential for the smaller systems, it adds up to about 1,236 MW. That's the potential that we see that is eligible under AB 1613.

One thing I want to point out before leaving this slide is we've used the term "Existing CHP" in the previous slide, and now we're saying "Existing Facilities." We're talking about businesses that are existing, not that they have CHP already, so, really, that has caused confusion in the past. So these are capacity where CHP could be added.

Then, another part of the competition for CHP is the price comparison between electricity and gas, and we analyzed electricity prices in terms of where they are now and we did that using the existing tariffs and prices for both electric and gas. And for the price movement over time, over the next 20 years, we have a 20-year time horizon, we pin that to the EIA 2011 Annual Energy Outlook Reference Case and the specific measure that we used there was the wellhead gas price. And the wellhead gas price determines the commodity cost of gas that goes into the gas prices, and we also estimated its impact on calculating a combined cycle power cost and used that escalation over time to reflect the escalation of generation cost for the utilities. There are a lot of details in all the tariffs and cookbook calculations and things, and so it's kind of difficult to work through all that, but that's the general idea of what we did.

The next slide compares the wellhead price forecast that we used this time vs. what was used in 2009. The red line is the 2011 Reference Case and that reflects about a 1.8 percent per year real growth in gas prices, whereas in 2009, and that was the 2009 EIA Stimulus Case, and that had a 3.4 percent increase in prices, so nearly twice as much. So while gas prices now are much lower and that would seem to be a very positive factor, I will talk later about the impact of cap and trade, but right now while I'm on this slide, I'll just say that, by 2030 in our analysis, we're adding about $2.65 to the cost of gas as a result of the GHG Allowance Cost. And that essentially would bring that red line all the way up to the line above it. So the growth rate with cap and trade for gas prices, effective gas prices, has now gone from 1.8 percent back up to over 3 percent. So it's a very significant impact on the economics, which I'll talk more about later.

The Intrastate Gas Transportation Cost, I don't want to talk too much about it other than that CHP is eligible for a specific transportation rate which is quite a bit lower than the standard rate that a boiler customer would have, and so the effective costs are reduced. And the costs are also reduced because a CHP customer would be consuming a lot more gas than just existing boiler load, so there's a double decrease effect, one is a shift in the right category, and the other is the increase in volume. And it acts to augment the savings from the avoided boiler fuels.

On to the electric prices. We looked at the rates in the five size bins that were in that technical potential chart. This is showing the 50 to 500 KW which is the smallest CHP size category we looked at. We analyzed the retail rates and calculated an average high load factor cost, low load factor cost, and an avoided air-conditioning cost for use in our analysis. And as you can see, the lower the load factor you go, the higher the impact or the effect of demand charges and other rates that raise the average cost much higher.

The next slide is for the largest category, 20 MW. I'm not going to say anything about that. All of the pricing information should be in the report when it is released. But what I was showing before was the average retail rate. The CHP customer or the generator isn't going to be able to save this entire rate, and so we calculate what we're calling an Average Avoidable Rate. When you operate a CHP system, there are certain unavoidable costs that exist. You can't avoid your customer charges. If you have forced outages, you'll trigger demand charges for the entire month, and so if the system goes offline in a forced outage two or three times a year, each time you'll have demand charges. And what's becoming larger over time are the non-bypassable charges for CHP, and those include the public purpose program charge, the DWR bond charge, and the nuclear decommissioning. The most important one is the public purpose charge and that's well over a penny now, it's approaching 1.5 cents in some customer categories. And the DWR bond charge is about a half cent. So it's a significant part of the non-bypassable charges. And then there are the standby reservation charges -- and this last bullet here, I want to correct, it's 10 to 30 percent of the retail costs are unavoidable and up to three cents per KW hour. So if you're making note, that number has been changed. So the difference between the blue line, which is the average retail, and the red line is what a CHP customer can actually save, and so it's these avoidable costs that go into the model for the economic calculation.

And within the five size categories, we have 12 technologies that were competing within the four categories of fuel cells, microturbines, reciprocating engines, and gas turbines. And for each of those technologies, we've estimated the capitol costs, the heat rate, the thermal energy available, and the operating and maintenance costs. And what this slide is showing is average U.S. capital cost. In California, the construction costs are somewhat higher than the rest of the country, particularly in the northern part, the Bay Area. So we increased these U.S. average costs by three to 10 percent, depending on the location, to reflect the increased cost. And also, we add emissions after treatment cost because all the reciprocating engines and the large reciprocating engines and gas turbines are assumed to have selective catalytic reduction systems. And in the economic analysis, those capital costs are then adjusted with any program adjustments like SGIP and tax credits, the Federal tax credits are included, and any other State Capital incentives.

And it's the combination of the energy prices and the performance of the CHP system within each of the market sectors that determines the economic value of CHP, which in turn determines the market.

I don't know if now is a good time to ask if there are any questions on the basic assumptions on cost and --

CHAIRMAN WEISENMILLER: Yeah, I have one question. One of the legacy systems in California that has been around in, say, San Francisco, there's a district heating system, certainly there have been district heating systems in San Diego and some of the other cities, Sacramento, actually we have the new central plant for the State facilities. So in your analysis looking at the potential, did you consider expanded roles of District heating?

MR. DARROW: We really did not. We looked at systems facility-by-facility, building-by-building, factory-by-factory. Some district heating systems focus on steam, they don't have car production, so, no, we didn't specifically look at district heating, although the facilities that would sign on with the district heating system are covered and analyzed individually, but the economics of maybe a larger more efficient system serving all of them together was not then considered.

CHAIRMAN WEISENMILLER: Okay, obviously district heating has been a key part of CHP in Europe like Denmark; do you have a sense of what sort of bump up we might get with that? Or is it just too tough to generalize?

MR. DARROW: Well, one thing is that of course you get an economy of scale if you're talking about a large scale system in terms of the lower capital cost and greater efficiency, so the economics, I think, would improve. But I don't know what extent you would -- I still think the way the California market is laid out, there's certainly opportunities for those systems in the city center and we have the capability, I guess, to analyze the technical potential by Zip Code and things, and try to specifically analyze a District heating opportunity, but to generalize about it from the overall State data, I don't know. I mean, I certainly think it would -- if you find a collection of willing customers with good steam and electric loads, and you could put in a large air-conditioning, cooling, chilled water system, you know, steam, then I think you would improve economics, but largely in certain commercial markets which are important, but they're not the biggest part of the potential, I think.

CHAIRMAN WEISENMILLER: Okay, thanks.

MR. DARROW: Well, I think I'll move on, then. We've actually made it to talking about the cases themselves, although not quite. This is just repeating the base case. The base case includes policy assumptions that are felt that they're in place and underway. Now, not all the details of all these programs are fully in place and underway, but they pretty much define the view of the future if nothing else changes. So that includes the 33 percent RPS and the cap and trade, and the AB 1613 export, and also maybe a short run avoided cost -- short run average cost pricing for the large export. And I'll go over in the next slides how we actually estimated these. I'll try to speed up a little maybe.

So cap and trade is -- the way it affects the market is, first it was the allowance price, which I've listed second there, the price assumptions, how much is the allowance price going to cost you, and then what is your fossil or carbon exposure. So, in terms of the quantity assumptions for the utilities, we base their average GHG emissions on the E3 GHG Calculator that is on their website and referenced in the CPUC website, it was their scenario 2, and then that gives GHG emissions over time. The emissions for CHP are based on the net increase in gas use compared to the avoided boiler fuel and the added generator fuel. And that's a specific rate of conversion.

And the price assumptions, we made a number of -- we looked at different options and eventually we decided to use the synapse forecast that has been used in the 2011 Market Price Referent Analysis and it's also been cited in the long term procurement planning process, and I'll show what that is on a later slide.

Two other things that are important in pricing is that, while it's not really set, about -- we estimated that a 90 percent reimbursement of the cost, or 90 percent of the cost increases for retail electric rates would be reimbursed, and that there would be no reimbursement for any effective fuel cost increases for onsite CHP systems. And it's our understanding of that's how the discussions are now that the program would work.

This is just the Synapse Forecast. We're using the dark red line, which is the real version of the nominal price increases are shown in the faint dotted line. So in 2020, the nominal price is $46.80 per metric ton, which translates to $37.47 in the way we use it in the model. So those are the price forecasts as we've used them.

One of the things that I was asked to do was, because this is an important and sensitive issue, is to determine how sensitive our output would be to the GHG assumptions, and I know I haven't gotten to the outputs yet, but it was felt that I should talk about this now, so I -- I'm comparing this to the base case, which I haven't yet presented, again, I apologize; but in the absence of the CHP Program as I've defined it, the CHP market penetration would be 18.8 percent higher, so turning that around the other way, going from no cap and trade to cap and trade is a significant reduction in market penetration for CHP.

Now we looked at using the low price track vs. the high price track and that does -- the low price would increase penetration compared to the medium price track by 5.8 percent, and the high price would lower it by 3.7, and then we also looked at taking away the assumption of electric reimbursement and that would increase market penetration for CHP by 11 percent because essentially in that scenario, you've got everybody having their prices going up. CHP fuel would go up percentage-wise a little more than the average electric, but that would be a difference. So I think this shows that cap and trade is a fairly strong inhibiter of market penetration in the case where you have reimbursement of the price impacts on the electric side, but not on the gas side.

So these are basically the average emissions of utilities and, again, this was taken from E3. They only went out to 2020, so we extrapolated from 2020 to 2030 and what we did, there were three utilities that were quite a bit lower, and we just assumed that they would stay constant at that very low rate, and that the four utilities that were higher, they would continue to reduce their emissions over time at the rate of about one percent per year. And, again, the gas emissions are based on 117 pounds per million Btu, it's a fairly homogenous fuel and so it's pretty much a straight calculation.

That covers the impact of cap and trade. The Renewable Portfolio Program is expected to have an impact on electric rates. We really didn't have a way to know what that was, so, again, we went to the GHG Calculator, Scenario 2, the Accelerated Policy Case, included the RPS and high energy efficiency, and in the results of that, they said that the average utility rate increase by 2020 was 1.64 cents per kilowatt hour. And so our analysis is in four time periods in five-year increments, so we average that out through 2020, and then after 2020 we just assumed that price increase was constant and would not go up.

We included SGIP with the .50 a watt, or $500.00 a kilowatt for non-fuel cell, this is a 50-50 payment with half up front and half over five years for systems that meet a minimum 80 percent load factor. We had some markets that don't meet that load factor and we prorated the annual benefits for those markets. And in the base case, we assume the program would end as scheduled in January of 2016. There is a program reduction of 10 percent per year for fuel cells and five percent for other technologies. And then the market -- we assumed the program ended in 2016.

Now, export pricing is an important issue and it's separate from the retail rates. The AB 1613 pricing, I believe all the IOUs have tariffs and SMUD has a tariff, and LADWP is developing a tariff. This is an example of a calculated tariff and it ranges from around 6.1 cents per kilowatt hour in the first time period to about 7.3 or 7.4 by the end. And these are based on -- oh, and there are scheduling costs that are included in that chart for systems over one megawatt. And I feel that the pricing does reflect long run marginal cost principles for CHP to meet.

So for the large export pricing, a lot of that is under development and discussion and also pricing is something that ultimately will probably have to come in the form of bidding process rather than being given a tariff rate or a price. But for the purposes of the model analysis for the base case, I calculated the short run average cost price which is in use now as part of the settlement agreement in some of those contracts, and it's fairly low, it doesn't provide full capital recovery. And for the medium and high cases, I looked at the 2011 Market Price Referent, which is based on a long run marginal cost of power to the electric power system.

And the MPR prices are about 25 to 35 percent higher than the SRAC prices. And again, the SRAC we used in the Base Case and the MPR pricing we used in the higher cases.

I've just got a few more assumptions before I actually tell you what it all meant in terms of results, but the medium case, we included the RPS and cap and trade, the same as the Base Case. The SGIP Program was assumed to be extended with this phased reduction in benefits over time until the benefits drop to zero. And we also redefined the export market with aggressive pricing, MPR pricing, and also aggressive market response. We changed the market response rates for paybacks less than five years to reflect the strong market response. This was a comment that was made in 2009, that these facilities, if they receive a strong signal and address issues of risk, they're ready to proceed with projects. Note that there is material in the back-up, there actually is no back-up material, I apologize, so I have to ignore that.

Then, the high case, we added a number of additional policy measures that would stimulate the prices and that includes the reimbursement for the GHG allowance component of CHP fuel costs. So, as I said, in the base case, there was no reimbursement of this added cost, where there was reimbursement on the electric side, and in the high case, we are proposing reimbursement. Although, in a lot of these scenarios, they're not developed detailed policy guidance on how you achieve it, but we're just assuming "if you did this, what would happen," not how are you going to make it happen.

And the next thing we looked at was eliminating the non-bypassable charges and, to a certain extent, eliminating what I'm calling double demand charges where the CHP generator has to pay a reservations charge, demand charge, but then also pay additional demand charges when the system goes down on top of that. So we went through the rates and assumed that those three non-bypassable charges could be avoided.

All right, so there are some additional assumptions that -- we call this High Electric focus electric utility participation, again, I don't have a specific mechanism for how electric utilities would participate, but in 2009 when we looked at the large market, we were assuming that people would be putting in combined cycle power systems and we were told that the business facilities, the refineries, chemical plants, their main focus is on their steam load, they're not electric focus, maybe simple cycle. So we assume that, with a different kind of participation and ownership rate that additional large combined cycle plants could be built that would meet a higher percentage of electric load for the same steam load. And so we call that the Electric Focus Case. We added a 10 percent State Investment Tax Credit with no size limit and no end date. We looked at an additional 10 percent reduction in out year, CHP capital cost to reflect a more active market, more competitive market, more competitive pricing, and removal of a lot of costs that occur in early entry market. And then more of a modeling change to reflect perception of risk, as we made the market more CHP friendly, we started dialing down some of these risk filters, percentages, so we allowed more participation in the market, and mean increase went up a percent -- I'll show that a little bit more. The last thing we added was a $50.00 a kilowatt T&D capacity deferral payment for CHP less than 20 MW to reflect grid support at the distribution level.

So this is just the table that shows percentages for each of the cases in the size bins, and those are percentages that reflect maximum market participation. So in each of these sizes, we held back some of the technical potential as a reflection of perceived risk, lack of space, lack of financing, not interested, but as you make the market better and better, we assumed that the participation rates would go up. And while this is a judgmental input factor, it is something that we tried to keep in line proportionately with the increases in market penetration without it.

So finally, we have some results. I apologize for leading up to this in such a long fashion, but…. If there are any questions now, or should I just jump right to the --

CHAIRMAN WEISENMILLER: Well, we are running behind, so let's jump on.

MR. DARROW: All right. So we ran the three cases, the blue is the Base Case, the red is the Medium Case, and the green -- and ranging from the Base Case, 20-year market penetration of just under 2,000 MW to the High Case of 6,100 MW. I'm just going to show another split of the three curves by the onsite market in the light blue, the export market in the maroon, and then the beige color is the avoided air-conditioned. So in the Base Case Market, 80 percent of the total market penetration is in the onsite market; only 11 percent is in export, and the reason for that is that the SRAC pricing doesn't provide much of any stimulus for new large CHP export projects. The AB 1613 tariffs, while higher than the SRAC price, are sometimes difficult for smaller systems to compete with because the avoided price is based on a large combined cycle system.

So anyway, in the Base Case, there's very little export penetration, it's mostly onsite. And in all of the sectors, the avoided air-conditioning is a fairly constant 10-11 percent of the total onsite penetration. In the Medium Case Market, the onsite penetration increased by 267 MW, that was entirely due to the one onsite measure that was added, which was extending the SGIP Program, rather than cutting it off in 2016. But changing the export pricing and the response to pricing brings a tremendous response on the export market, over 1,400 MW increase and about, between the Medium and High Cases, export market becomes 40 to 46 percent of the total market. In the High Case, which had a lot more onsite stimulation, there's a 1,700 MW increase compared to the Base Case on onsite market from the T&D support, the extended SGIP, and all of those measures. And there's about maybe a 33 percent increase in the market penetration for the export market due to the focus on combined cycle technology and maximizing electric production, and also the impact of tax credits.

In terms of where the market is distributed, again, because of its geographical location in the businesses within its territory and, to a certain extent, the pricing levels, PG&E has 43 percent of the projected market penetration. And this is the Base Case.

While we were talking through the other charts, I talked a bit about the small vs. large CHP market and this table shows the breakdown for the three cases of market penetration between those three markets, below 20 MW and above 20 MW for the High Cases, and I think I pointed out that the changes in the onsite and export as I was going through the charts. But I think the fact is that the two markets respond very differently to the incentive factors, the onsite market is very sensitive to the retail rate structure, gas and electric, and incentive factors with the SGIP, and cost and performance improvements. A lot of the smaller technology has more room for future improvements, it's more of an emerging technology, or at least the experience with packaging and installing. And Investment Tax Credits, T&D Support, those things all support the small market.

The large market is primarily an export market and, so, the number one, number two, and number three factor, I guess, are the export price and the conditions for export, but the market also responds to Investment Tax Credits and that.

So we calculated the GHG emissions savings. If I'm running long, I'm not going to try to go through this in a lot of detail, but basically a CHP system produces electricity which either avoids the need to generate electricity at the grid, or is fed back to the grid, and the impacts are shown in the lines there. In terms of avoided emissions for that added power, we used the ARB assumptions that were in the Scoping Plan, which was 963.4 pounds per MW hour and line losses of 7.8 percent. Only the onsite markets are affected by line losses, it was assumed that the export market is fed back into the grid and it is subject to line losses, so the savings are a straight one for one with the utility generation rate.

And then the next thing is the impact of the added fuel use, which is the difference between the avoided boiler use and the added CHP use, and I've got a little formula there for how we calculate it. But this calculation, it goes on for each of the market sectors, the load factors in the model, the sizes, based on the performance of each of the individual systems. And it's added up. But we compare it to the benchmark that ARB set up.

So the results show that, by 2020, the avoided GHG emissions range from 1.4 to 4.5 million metric tons, in 2030, it is gross 1.7 to 5.6 million metric tons. I probably should leave it at that, but we also looked at it in that this is compared to current situation. In the real world, everyone is going to be reducing emissions together, cap and trade, the utilities are going to be reducing emissions, so the actual emissions over time are going to be affected by the shielding effect that onsite CHP has in terms of avoiding the need to purchase renewable power systems at the utility. If their load is reduced by 100 megawatts and they're required to meet 33 percent of their new load with renewables, then effectively 100 MW of CHP is avoiding the purchase of, say, 33 MW of renewable in the out years. So we looked at it in this way, I don't know if it's really fair to say, "Oh, well, CHP isn't meeting its goals." It's showing that the goals are being met and that the differentials, as you reach the target, get smaller and smaller.

The thing to point out is that export projects don't diminish the utilities' requirement to meet -- it doesn't diminish their capacity targets because it is considered their capacity, and so the GHG impacts of exported emissions become part of the utilities' average emissions. And so the two higher cases where the emissions or the penetration is mostly -- or largely export -- half export -- then those don't come down as much. I know I'm behind --

CHAIRMAN WEISENMILLER: Yeah, why don't you just wrap up with this slide and then we'll take questions?

MR. DARROW: Okay. I think people can read the market penetration, or the conclusions that I have. If I can just maybe go to the last one, is that -- I don't want to lose site of the fact that the CHP does benefit customers individually and support California environmental goals. And the GHG emissions savings, depending on whether you calculate it one way or another, the focus, I think, should be on the cost-effectiveness of the benefit that's being provided, that a lot of technologies are being chosen to meet this sweeping goal through cap and trade, and CHP is helping to meet the goal and maybe the contribution is cheaper than some other alternatives.

And for individual customers in the Base Case, they're saving $740 million a year in energy costs through this market penetration, and in the High Case, they're saving $2.9 billion per year, so there's a private benefit and still public benefit.

CHAIRMAN WEISENMILLER: Okay, thanks. You covered a lot of ground. Any questions?

MR. NEFF: Are there any questions from the audience? Could you please approach the dais or the podium? Please state your name for the record.

MR. SIMONS: George Simons with Itron. Ken, when you guys looked at the GHG emission benefits, you used the CARB numbers. Those are essentially carbon neutral goals. Did you look at the impact of CHP where you could actually get to negative GHG emissions?

MR. DARROW: Um -- I would say no because I don't understand in the case of CHP, it's always going to have a certain fossil signature, what necessarily you mean be negative emissions.

MR. SIMONS: Okay, so some of the analyses that we've done on the Self Gen Program, we found that it's a critical feature on the waste heat recovery side that, at best, when you're competing -- when CHP is competing against combined cycle, the only way it can go to a GHG negative position is through waste heat recovery, and increasing waste heat recovery, because 200 of the hours during the year are essentially on the peaking side, so the other vast majority of the number of operations during the year have to go up against these combined cycle very high efficiency plants; so the only way CHP can compete on a GHG basis is to increase waste heat recovery. And we think that CHP can do that very successfully. Secondly is, did you look at both the NO_x impact on GHG for oxidant, as well as the use of biogas for CHP?

MR. DARROW: Let me respond first to the original comment on GHG. Our systems with the heat rates, in each market we assumed a different thermal utilization and thermal recovery, and I guess our kind of net heat rates were running around 6,000, 6,100, a really super designed CHP system you could have a net heat rate in like the 4,500, less than 5,000. You're certainly going to beat a combined cycle plant that is operating around 7,000, and then adding line losses to that. So I think, in that sense, I feel that the CHP systems that are focused on heat as a thermal recovery mode all beat the standard of a combined cycle power plant. In terms of the criteria pollutants and NO_x emissions, we did not kind of maintain that tracking. We did, in building up the plant cost data, we included cost so that all these technologies met CARB '07 emission standards. But we have the ability to track criteria pollutants, but we really didn't update the performance of the technologies this time and we didn't really output that, so we didn't look at the output. And now I've forgotten the third question.

MR. SIMONS: It was about biogas.

MR. DARROW: Oh, biogas.

MR. SIMONS: Because of the methane.

MR. DARROW: Yeah, well, all types of CHP are included in the existing CHP analysis, but the market penetration is based on natural gas systems. We were not able to add biogas. In 2009, it was a separate study on, I guess, biogas opportunities, which might add I guess another 400 MW of potential in the state. But, no, we don't include the biogas or biomass in this estimate.

MR. SIMONS: Yeah, and in no ways do I want my comments to be a criticism of ICF, I think you guys did a great evaluation job, it's just that I think those are additional benefits that need to be taken into account because, again, some of the work that we've done, you know, because of the methane capture is such a powerful GHG emission reduction strategy, and because California has a lot of biogas, that has been underutilized, that should be worked into -- I think personally that should be worked into an analysis.

MR. DARROW: I agree. I mean, it's certainly a low hanging fruit, it's a hot market. The upside potential is fairly limited is all, I mean, in terms of strategic thinking, in terms of getting businesses going and getting projects underway, those markets are going very strongly.

CHAIRMAN WEISENMILLER: Yeah, it would be great if you could submit biogas analysis you've developed at Itron into our record here?

MR. SIMONS: Sure, absolutely.

CHAIRMAN WEISENMILLER: Thanks. Next.

MR. BARKER: Dave Barker with San Diego Gas & Electric. I just had a question about the categories Onsite vs. Export. Are you basically taking a facility and splitting it into onsite and export amounts? Or are the exports somehow different, or different facilities, or -- could you explain the difference, the categories?

MR. DARROW: We took the same facility and cut it in half and put half of it in one bin and analyzed it as an onsite market, and half of it in an export market and analyzed it as export. And I realize there's some potential pitfalls of doing that, but it was the easiest way to analyze it. We did essentially, you know, I would say we saw there was 10 MW of export potential as part of a total 60 MW project, we would still put that 10 MW in the over 20 MW export size bin, just to reflect the economics of large systems. But to analyze it with the different pricing, we ended up splitting them up.

CHAIRMAN WEISENMILLER: Thanks. Next.

MR. PINGLE: Hi, Ray Pingle from Sierra Club. So as I understand your report, you're saying there's roughly 15,000 to 16,000 MW of technical potential CHP in the state. Is that correct? And that -- but even in the High Case, you're saying that there's a potential of 6,100 MW, which would still be shy of the Governor's goal of 6,500 MW? Am I understanding that correctly?

MR. DARROW: Yeah, I didn't call it "potential," but market penetration, I look at the technical potential number is, I mean, you know, a BMW dealer could come to California and say he has a potential market of five million customers based on certain estimates of their income, etc. It's a long way from the technical potential to having an economic project and wanting to go forward with it, and that's why the numbers -- we're getting about, well, whatever percentage six over 16 is, and that's the High Case. So there is quite a lot of the technical potential that doesn't move forward, or is not likely to move forward as a project.

MR. PINGLE: So it sounds like we need to do as much as we can to create favorable conditions to realize the maximum penetration, and it sounds like there's a lot of savings that could help pay for some of those incentives, as well. Thank you.

MR. DARROW: Thank you.

MR. SCHWARTZ: Hi. Andy Schwartz from the CPUC. I had a question regarding -- more of a question or clarification on Slide 18 where you talk about the sensitivity of the market opportunity for CHP owing to the CO_2 allowance price under cap and trade. It sounds like, based on what you presented, that on this slide, the cap and trade program actually has an adverse impact on the market opportunity of CHP. And I was just wondering how much of that is driven by the assumption that 90 percent of the revenue is returned through rates.

MR. DARROW: Well, I think, if going back to the slide, which I don't know if I can bring it up for everyone, oh -- I think if you compared the case where we had no electric reimbursement and said, okay, that's the new Base Case, then the reimbursement reduces the market by another 7.5 percent, so just to go here -- if there's no reimbursement, and this is your basis, and so the impact to reimbursement is -- sorry -- the impact is seven percent and then the impact of -- so the adverse impact is reduced from 18 to 11 percent.

MR. SCHWARTZ: Right, but again, just to be clear, so without a cap and trade program, according to this slide, you have 18 percent higher penetration CHP whereas --

MR. DARROW: Right, with the assumption that 90 percent of the electric rates are reimbursed and none of the gas costs.

MR. SCHWARTZ: Okay, and so the assumption where there are no electric -- I'm just trying for clarification -- if there's no reimbursement under the cap and trade program, then the cap and trade program results in an 11 percent increase in the market penetration of CHP relative to the Base Case?

MR. DARROW: Yeah, that would become the new Base Case, so you'd raise the floor up to that level.

MR. SCHWARTZ: Okay, thank you.

CHAIRMAN WEISENMILLER: Yeah, Ray. You'll be the last question.

MR. WILLIAMS: This is Ray Williams from PG&E. I just wanted to follow-up on some questions that Andy had asked, just so we're on the right slide here. So I guess, you know, from my simple perspective, in the wholesale markets, cap and trade costs will be reflected in wholesale commodity prices and, as part of the QF CHP settlement, which a number of us were very involved with, the compensation was structured so that it would increase once the cap and trade program came into play. So, in other words, on the export side, one would figure, given the fact that compensation will increase, as long as CHP generally is more efficient than the market, they actually should make out pretty well under either a low price or a high price scenario. Now, if CHP is less efficient than the market, one might expect the opposite effect. So just looking at the low price and the high price, I'm a little confused relative to, you know, what I see in terms of where wholesale market prices are going, and looking at efficient CHP.

MR. DARROW: Well, I agree with you that the wholesale market is different and our assumptions, which I may have glossed over as I was moving forward, was that for the export market, the cap and trade does not affect the market or the pricing because there are mechanisms to capture the price in terms of who is responsible and that price is covered and it doesn't affect the return to the generator. In this particular, when we did it off the Base Case, which I mentioned was an 80 percent onsite scenario with very little export penetration, so what you're looking at is, I guess, the effect of the retail markets, which are strongly affected. And I agree with you that the export markets in our logic should not be affected much or at all.

MR. WILLIAMS: Right.

CHAIRMAN WEISENMILLER: Thank you. Ray, you're going to be on the panel this afternoon and one of the things, certainly, would be to dig into this more. I know, certainly, Cliff and I are both getting letters from a number of existing projects wondering what the impact of this is going forward, but, again, pick up that more this afternoon.

Certainly, thanks for your presentation this morning, you covered a lot of ground. We appreciate getting that pretty broad framework for the subsequent panels. And hopefully you'll be around long enough to the extent that there are other questions, and that people have an opportunity to catch up with you.

MR. DARROW: Sure.

CHAIRMAN WEISENMILLER: Let's go on to the next panel.

MR. NEFF: Thank you, Ken. I do want to make aware that, as Ken mentioned during his presentation, that we're anticipating the draft version of the report on the 27th, and that will provide the opportunity for people to submit written comments on the full report and the closing for comments is on March 9th.

So now we're going to focus on the Small CHP Panel, which focuses on the CHP market, and as Ken described, there are different drivers and different barriers for the different sizes of technologies. And through this process, we're going to try and identify what works and what doesn't through first hand experiences of both people who have installed CHP at their own facilities, and then some CHP manufacturers who have installed it at other people's facilities and have had experience in the California market.

So we'll be starting with Sam Ruark from Sonoma County. He is the Project Manager there at the Local Government Partnership. He is a former Sustainability Planner for Marin County and has worked on sustainability initiatives in the nonprofit, small business, and local government sectors.

MR. RUARK: Thank you, Bryan. Good morning. Is everyone awake out there? All right. So, yeah, I'm Sam Ruark with Sonoma County, managing management of the Sonoma County Energy Watch Program. I'm going to talk about our comprehensive energy project which a key component of that was the 1.4 MW fuel cell that we installed.

Just to give a little context to our commitment to sustainability, within the past decade we have installed a turbine at our landfill to generate five to six MW of landfill gas. We have a robust local government electric vehicle partnership. The third line there is actually a typo, we don't have 820 MW of solar, that would be great, but we have 820 Kilowatt of solar within the county operations. We've got this new 1.4 MW fuel cell, we're looking at 1.1 MW of biogas development. Our Energy Independence Program has financed over 5 MW of solar, and in the county as a whole, we have 50 MW of solar, we're actually averaged one MW per month being installed in Sonoma County right now. And my office is working on several different energy projects financed through Home Bill Financing, the ARRA funds, and Qualified Energy Conservation Bonds, and then my program, the Sonoma County Energy Watch, saves about five MW hours per year to all of our customers.

So in 2008, we decided we wanted to do a comprehensive energy project. We put out an RFP for an ESCO to assist us with this. We selected Aircon Energy and they did an investment grade audit of our facilities, they came up with 180 energy efficiency measures that we could do. We scaled that down to 101 measures. And then the process, once we got it to 101, we figured out, "Okay, what could we actually do? What can we take to the bank?" And overall, our objectives for the comprehensive energy project were cutting our greenhouse gas emissions to meet our goals set by our board, we wanted to have a positive financial impact, and we also wanted to remove some of our aging infrastructure in our County campus. A lot of the buildings there were built in the '50s, '60s, '70s, and some of them were starting to see some serious degrading of equipment.

So, the CEP or Comprehensive Energy Project essentially became a project of 38 energy efficiency measures in 24 buildings, or 20 buildings, actually, with 1.3 MW hours of savings. We did new motors and variable frequency drives on our HVACs, we did a major retrofit to our central mechanical plant, which feeds power and hot and cold water to 14 buildings on our County campus. We did water retrofits, saving 20 million gallons of water per year, we also installed an ozonator for our laundry facility. And the biggie -- the thing that really made it all happen and made it possible was the 1.4 MW fuel cell.

So the one we installed, here is a photograph of it, the stack is here on the left-hand side, essentially Fuel Cell Energy is the company that manufactured it, it's a molten carbonate fuel cell, DFC 1500, it essentially generates 10,693,000 KW hours per year, it also produces 45 billion Btus per year. The great thing is it produces essentially no NO_x or SO_x, you know, it's designated clean by CARB, and it reduces -- when we modeled it, it showed that we reduced our greenhouse gas emissions by 69 percent vs. the grid power, primarily because we have a waste heat recovery unit on this fuel cell. As kind of a very middle of the top thing, you see the stack, and there's a pipe at the top, that's basically the cane unit that captures the waste to heat in order to offset the needs of our boilers to heat our buildings.

Most of you know how fuel cells work, so I won't go into this, but essentially it's natural gas, or biogas coming in, we use natural gas and water to create heat, to separate the hydrogen off of it, in order to create electricity. And then you've got heat and water as your byproducts. And I would love for Fuel Cell companies and manufacturers to one day create a system where it's closed loop so we're not having to feed water in and let water off, so there should be some way to capture that water eventually. It also creates DC power and then we convert it through inverse to AC.

Supposedly, I don't know if this is still true, but six months ago, it was the largest fuel cell in California at 1.4 MW, there's a lot of other entities looking at us on this particular fuel cell. You know, it is adjacent, is right at our central mechanical plant, so it is really perfectly situated. Essentially, it is 47 percent electrical efficiency plus 20 percent due to combined heat and power. So, supposedly, it's compared to -- a fossil fuel plant is 33 percent, or those. And essentially there's no transmission losses because it is right out of a 12 KV loop; we can produce the power and feed it right in. It is powered by natural gas. We have looked at biogas, however, the biogas costs were too high for us, and it kind of screwed with our financing. One of the key things that made it work for us was the SGIP. This project, you know, was a $10 million fuel cell, essentially, and we got a $3 million incentive through the SGIP.

The graph here is basically our load shape. You know, basically our demand at night is 850 KW, but in the peak summer it can go up to 2,500 KW, so you know, there are times, pretty much every day, where we are both exporting and importing power to and from the grid. Our electric annual utility bill for the County is $1.5 million, and you know, our natural gas bill did go up by $350,000 per year based on all the natural gas we're now using for the fuel cell. However, we are through the whole Comprehensive Energy Project as a whole, we're reducing our utility costs by $1.5 million per year. And the key thing to realize is the fuel cell payback was seven years.

This is a photograph of our board, Board of Supervisors, essentially they said, "We want you to do this, we want to continue to be leaders, but we can't put any General Fund money toward this, so you've got to make it cost neutral." So we looked at both private financing and Municipal financing via bonds, and the better interest rate came from the private market. And Banc of America, not Bank of America, I don't know what the difference is, but they essentially were the ones that funded the project. And it was interesting timing, too, because we essentially starting going to the bank in December of 2008, so at that time, getting a loan was tough, but we had really good clear investment grade audits to present and the bank received it, and after studying it for a while, they decided to loan us the $18 million needed to do the project.

So, yeah, total project cost was over $22 million. We received almost $4 million in incentives and grants and rebates, so we financed $18.7 million. Our interest rate was 4.98 percent, we're going to pay it back over 16 years. We estimated the annual energy cost escalation to be 5 percent, we have positive first year cash flow at year 12. And so, essentially over the 16 years, we're going to be paying $31 million for this project; however, if you take it over a 25 year life, which is what we expect, we'll save $38 million. So this is a positive cash flow project for us over the long term.

There's the check, $3 million. Here is the graph showing the cost. We basically modeled it so that we save a little bit of money every year, and then at year 12, it levels off, and then in the year 16, we're totally done paying for it. So it allows us to remain in that positive cash flow situation.

So based on how the project is modeled, these are what we're going to see. Now, we're in the process of the Measurement and Verification process, we are not actually getting the energy savings that were modeled by the ESCO, we are short of those by about 20 percent. And what we see is that we need to fine tune our operations, and so we're in a process of retro commissioning that right now, realizing there's times where the fuel cell is firing and we have hot and cold water both go into our 12 KV loop, so why aren't we sending chilled water and hot water at the same time to the buildings, so being able to fine tune that is where we're at right now. However, if all of it gets fine tuned the way we can see it's possible, it will reduce our greenhouse gas emissions by 6,135 tons per year, it will reduce our electricity use through the efficiency, and to the fuel cell by 13 million Kilowatt hours, we'll save almost 20 million gallons of water and we'll cut our utility bill by up to $1.6 million. And so basically we take that utility savings and pay back the debt every year, so we're continuing to get the same amount of utility budget every year, but instead of paying the utilities, we pay for the debt.

So the great thing is it had no general impact, like I said, it replaced some of our old worn out equipment, and really, you know, it helped create jobs and collaboration and got the County to be able to walk its talk related to greenhouse gas emission reduction, cost savings, and cutting utility bills.

So here, this is the main slide, these are the challenges we have run up against. The first thing is that, when we were sold the fuel cell, we didn't realize we were working through our ESCO and we didn't really have direct communication with Fuel Cell Energy, which is we didn't realize that we could not have the fuel cell operate based on our load shape, and then, you know, we had already purchased it and it was already in the process of being built, and we realized, "Oh, this thing has to operate 24/7." And so we went to PG&E and we said, "Okay, we're going to have some excess power here, we want to connect to your grid." And we knew we were going to connect to the grid anyway, but we said, "We want to feedback some of this excess electricity into the grid." And they resisted. It took essentially four months of constant negotiation and trying and trying and trying, and finally they said, "Yes, we'll take it." At that time, 1613 had already been passed, so we were waiting on being able potentially to get a tariff for that. There was this back and forth, as you all probably know, what the CPUC related to as FERC, or is it CPUC who makes a ruling on this, and then after several years it feels like finally the CPUC has ruled on 1613 and we know what 1613 says.

So we have a combined heat and power facility, we export power to the grid, however, we've been denied a tariff. Essentially, PG&E tells us that the reason they're denying us a tariff is because of our SGIP, that we got that in 2010 budget cycle, and that we -- if we had gotten it in 2011, maybe we would be getting a tariff. However, as we read 1613, it doesn't say that we should be denied a tariff. What we export to the grid is very minor, we only export 5.6 or 6.0 percent of our electricity to the grid from what the fuel cell produces. That's only 600,000 KW hours per year, you know, at six cents per KW hour, that's only like $36,000 or $37,000, so it's not much. But if we could utilize that money through a tariff to do more energy efficiency projects, we would greatly benefit. So you know, we're reaching out to others, I've been in communication with Bryan Neff here at the CEC, we've been in constant contact with PG&E, we've heard different things from them. Part of their group says, "Oh, yeah, we can pay you," and then part of the group says, "No, we can't." So we're kind of in this gray zone right now. So any assistant that any of you can provide to that will be a great help.

And then just the last thing I'll say -- oh, PG&E stands up. Thank you!

CHAIRMAN WEISENMILLER: PG&E is here to help. Why don't you finish up?

MR. RUARK: Awesome. So I'm just going to say one more thing before I wrap it up and then Ray can go, which is -- so just on the technical issues related to the fuel cell, the only thing -- the stack itself is working great, we've had problems with our water filtration and the water filtration -- our water has more silk in it than it was tested at before the fuel cell was installed, so we're having to replace filters every week vs. every six months. And also, water consumption has gone up, and natural gas consumption has gone up. But, you know, there's been a couple other issues that have come and gone. And we also realized that whenever the fuel cell goes down in the middle of the day in the summer time, we get those demand charges. So we're asking Fuel Cell Energy, which they're complying with to do any maintenance that they have related to the fuel cell in the off peak times. So, with all that, that’s my presentation, and I would love to have any checks or guidance from PG&E on this opportunity.

MR. WILLIAMS: So, again, my name is Ray Williams, I'm from PG&E. I'm in the Energy Procurement side, so I generally deal with the large projects, not the small ones. But I did try to talk to some people who are very involved with the SGIP Program. So I'm sort of reading off my Blackberry here, but essentially what I understand is that, when you signed up for the SGIP Program, at that time there were no grid deliveries as part of that program, so it's not really AB 1613, it's the way the SGIP Program was set up at the time. And so you've got -- PG&E is a Program Administrator and, you know, he himself is not authorized to be at variance with the rules that are in front of him based on when you signed up, so that's probably why it feels like kind of a stiff arm. And if you've talked to three or four different people at PG&E and you got different answers, then I'll try to deal with that. I think, though, going forward, exports are allowed in the new program, and so the natural question is can you apply that retroactively. And I think the answer is yes. But the process is you have to go back and petition the PUC to get a rule changed for that old program, and that should be relatively straightforward. And, you know, I talked to the program administrator for PG&E and we at least would support that, we would provide a letter of support for that.

MR. RUARK: Great.

MR. WILLIAMS: So I was able to get that much done in the last day or so, so hopefully get that petition in, we'll file the letter of support, and hopefully we can take care of this.

MR. RUARK: Great, that would be fantastic. Thank you very much.

CHAIRMAN WEISENMILLER: That would be good. I don't know, Andy from the PUC, any comment?

MS. KALAFUT: Jen Kalafut from the PUC. Yeah, and Ray is right, it's not the AB 1613 that puts any limit on what other programs you can participate in, but I'm not exactly sure or clear on the 2010 SGIP Program and where it says that exports are not allowed. And so I think it would be helpful if PG&E could point to the rules in that program specifically where they're interpreting that provision.

MR. RUARK: Great, thank you.

MR. RECHTSCHAFFEN: Sam, I had a question. You said that so far the savings are 20 percent less than predicted. How has that affected your financing? And did you have a Performance Guarantee with the ESCO that did the work?

MR. RUARK: We have a Performance Guarantee based on the energy savings, however, the contract was written before my time, but basically there's nothing in the contract that says they will pay us back if we don't meet those savings. Basically, the Performance Guarantee says if we don't meet the savings, they'll come in and try to rectify it through some, you know, retro commissioning, things like that, which we're in the process of doing. What was your first question again?

MR. RECHTSCHAFFEN: How is that affecting the bottom line, essentially?

MR. RUARK: The good thing is we have been able to do other energy efficiency projects through ARRA and through on-bill financing and such, and also we've seen significant cost savings based on natural gas prices going down, so for this year we're fine and we're probably going to be fine for the next few years, but if natural gas prices spike again, then we could see some issues.

CHAIRMAN WEISENMILLER: Okay and I had a clarifying question. When you talked about a seven-year payback, that was once you netted out the SGIP payments or the incentive payments?

MR. RUARK: Correct.

CHAIRMAN WEISENMILLER: Okay.

MR. RUARK: And that was based on a five percent electricity cost escalation from PG&E.

CHAIRMAN WEISENMILLER: Great. Thanks.

MR. RUARK: You're welcome. Any other questions?

MR. NEFF: Thank you, Sam. I'll ask you and the other panelists to come sit at the table and we'll move on to the next presentation.

The next presenter is John Hake. He is an Associate Civil Engineer with East Bay Municipal Utility District in Oakland, California at East Bay MUD's main wastewater water treatment facility. He is a member of the Process Engineering Group with a focus on energy issues, power sales and purchases, efficiency and demand management.

MR. HAKE: Thank you. Good morning. My slides are going to be a little bit different from what the handouts are, I've added a few, but I'll try and get through those quickly.

So I'm here to talk about East Bay MUD's Combined Heat and Power Project, which includes a Resource Recovery Program and our new biogas turbine. So I'll start by talking about the Resource Recovery Program and the opportunity we saw there in terms of increasing our biogas potential, and I'll also talk about the new turbine that we just recently installed. This is -- we've encountered a number of challenges in proceeding with both these projects, and I'll end up with some recommendations about how we can -- maybe some specific policy recommendations for improving the potential for combined heat and power, specifically, in the waste water treatment plant sector.

So over the last decade or so, East Bay MUD has seen a decline in our wastewater treatment flows, which is providing us with some unused capacity. Some of this is due to water conservation, and also the migration of industry out of the City of Oakland, and some of the industrial wastewater flows. So what we've found ourselves with was some unused anaerobic digester capacity and, because we're also feeling some pressures on maintaining low -- or reducing the increase in water and sewer rates, we thought that we might be able to earn some additional tipping revenue and there was an opportunity to put high strength organic waste into our digesters to increase our biogas production.

So over 10 years ago, we started by accepting some of the waste that I show here in this slide. Most of these are liquid waste, however, we're also receiving solid food waste which was something we started in 2004, with the Energy Commission assistance, and we're always considering other possibilities. And here's a couple pictures of our solid liquid waste receiving facility in the upper left photo, which shows a food waste load being received, that's solid waste that we slurry and then pump into our digesters, but most of our waste comes in tanker trucks.

I've included this graphic from the staff paper that was prepared by Commission staff and from -- I think it was part of the 2009 IEPR process, and I've included this because it's nicely aligned with the Resource Recovery Program at East Bay MUD. It shows the cumulative increase in biogas production and energy generation from accepting some of these wastes into digesters at wastewater treatment facilities for co-digestion. And East Bay MUD is accepting fats, oils and greases in these food processing wastes. Because we're located in an urban area, we don't take dairy manures, although there are other wastewater treatment facilities that do that. But this shows the increase in potential, and I think the Resource Recovery Program at East Bay MUD mirrors this.

So we've been able to substantially increase our biogas production, doubling it over the last 10 years, and there's a concurrent increase in our energy generation, and there's also an additional benefit of diverting these wastes away from landfills in most cases.

Over the years, as we increased our biogas generation, we found ourselves outstripping our capacity to generate electricity with our existing IC Engines and we were flaring gas for quite some time, and so in 2006-2007, we saw the opportunity to add to our generation, to be able to utilize this biogas and with a secondary benefit of increasing our onsite power reliability.

So in 1986, our cogeneration system was founded with three internal combustion engines and, in 2011, we completed construction of our new solar turbine 4.6 megawatts, and it's been operational for a few months now. Here is a photo of our facility, both old and new, you may have driven by our plant as you approached the Bay Bridge Toll Plaza, so this might look familiar to you.

And one of the metrics that we use to measure the success of our program is how much of our onsite power demand can be met by generation. And before we started the program, I think we were a typical wastewater facility in that we were meeting about 40 percent of our onsite plant demand, and over the years, by increasing that, we couldn't get quite up to 100 percent, but we were consistently above the 80 percent over the last few years, and now with the new turbine, we're projecting that we will become a net energy producer and be in excess of serving our onsite loads.

So here are some of the challenges that we encountered in both the R2 Program and with installing the new turbine. The ones I've highlighted in red, I'll talk about in a little more detail on some of the subsequent slides. But it's not just a simple matter of throwing these wastes into our digesters, there are a lot of process impacts in terms of toxicity and stability. We need to ensure that we continue to meet our wastewater discharge permit conditions. Some of these wastes introduce contaminants that might damage equipment. They also create new odors that we haven't smelled before, that we had to deal with, and new contaminants in our biogas that we also have to scrub and condition before we can fuel the turbine.

We have some of our competitors, meaning our neighboring wastewater facilities, are starting to look at what we're doing and so they're starting to accept some of these wastes, as well. So those are some of the challenges with respect to the R2 Program. But what I'd really like to focus on more here are some of the things related to our turbine installation. But I think maybe the main message I want to convey here is that, you know, the things that we're doing with the Resources Recovery Program we think is great and wonderful, but it's also very challenging and it's not business as usual for wastewater treatment facilities, at least not yet.

Our solid liquid waste receiving facility where we take these wastes was funded in part by a California Energy Commission grant that was awarded in 2002, and we completed construction of this facility in 2004 with a half a million dollars from the California Energy Commission, and that was a significant factor in our decision to move forward with developing that facility.

We did not receive grant support for the turbine because, at the time that we were moving ahead with that project, turbines and engines and other combustion technologies were not -- the funding was not available for those at the time.

We upgraded our interconnections with our utility, PG&E, and this is a lengthy process, it starts with the design and ends with -- it doesn't end until construction is completed, so for us that's been a five-year process. It involves a lot of design reviews and testing, inspections, installation of a specialized transfer trip which involved coordinating with the AT&T for communication lines. So there were a lot of moving parts to the interconnection process. Fortunately, our PG&E Project Manager was very experienced and was able to guide us through this, but it is a very challenging process and a very costly one. Our interconnection upgrades cost us approximately $1.3 million and, when I looked back historically at what we paid under our Special Facilities Agreement in 1986 when we installed our engines, at that time we spent $23,000 in interconnection and upgrade improvements. So that's quite a substantial cost increase.

The coordination and scheduling can contribute to construction delays and there are -- PG&E is a large organization, and we're dealing with a lot of different groups; fortunately, our Project Manager was very capable and helped shepherd us through the process, but there were times when we would have job site meetings and there would be over a dozen folks there from PG&E, so it was quite a lot of communication going on and, so, really on both sides of the interconnection process we are fortunate to have a very experienced Electrical Engineer to help us get through this process. But for smaller wastewater utilities, this could be quite burdensome.

One of the main challenges we see now with regard to funding -- and this is a self-financed project -- is the decline in wholesale power prices over the last few years. We were very disappointed in the recent CPUC decision that categorized all unbundled RECs in a Category 3. We felt that, because we are in-state generation connected to a California Balancing Authority, that we really should have qualified for Category 1, and if we had, I think that it would increase the value of the RECs that we might sell for the power that we use onsite where the only way for us to monetize the value of that is to unbundle the REC and sell it.

Also, we've talked about SB 1613, the feed in tariff, we feel that it might be of some benefit if the prices were administratively determined and specific to the technology. Right now, it seems to be based on natural gas pricing, and we're not certain that that's really reflective of the real value of some of these smaller renewable energy projects.

You know, based on the decline in the wholesale power prices and the decline in the REC value, that's greatly increased our project payback period over what we had estimated originally, so in 2007 we were thinking that our payback might be somewhere in the range of seven to 13 years, but now we're thinking that payback is probably going to be more on the order of 15 years.

Transaction costs for surplus power sales can be high. For our engines, we had an existing Power Purchase Agreement with PG&E for the sale of as available power. Originally we sought an amendment to include the turbine under that existing contract. Ultimately that was denied in favor of the new family of QF Agreements which is now coming out under the Settlement Agreement, and we were told to wait and do that, you know, at the time the settlement went through. So, currently, we have no way to sell surplus power for the turbine. I mean, we understand that there are a lot of alternatives out there, we'll be looking at the new QF Agreement, as well as other alternatives, but for -- we're a wastewater utility that's primarily focused on onsite generation, so for us the one or two extra megawatts that we sell, and if we're trying to do that on a wholesale market and dealing with CAISO issues, and scheduling coordinator requirements, for many of you that may be things that you're very familiar with, but for those of us at a wastewater facility, this is kind of new terrain for us and it's not always easy for us to kind of sort out how we should sell the little surplus that we have.

And so, mainly the recommendations that we have looking ahead and, again, this is from the perspective of a wastewater utility, is the grant funding is very helpful in terms of us deciding to proceed forward with projects. The interconnection process, to the degree that can be streamlined and simplified would be wonderful. And then, in terms of stabilizing the revenue that we can expect to receive for this renewable power in the future, things like the REC value and firming that up, maybe putting some of these unbundled RECs in Category 1 where we think they belong, as well as tiering the feed in tariff to reflect the value of renewable energy, we think, would help to stabilize revenue and make it easier, provide a little more certainty to facilities like ours as we decide to proceed with these projects.

One proposal that we have was to put together a program for biogas specifically, similar to what was done for the California Solar Initiative. So what that might involve is dedicating funding for grants specifically for biogas development, and also the feed in tariff and having a specific one that addressed biogas. And so this might apply not only to wastewater treatment facilities, but landfills and dairy digesters, as well.

We think there's a lot of additional value to biogas as a renewable energy source because it's not intermittent, it could serve as a baseload renewable, and you know, potentially provide peaking power if there's funding for storage, and it's eliminating a potent greenhouse gas, methane in particular. So that concludes my presentation and I guess if there's time I can take some questions.

CHAIRMAN WEISENMILLER: Yeah, thank you very much. I wanted to just understand your interconnection situation better. What voltage level are you interconnecting? I assume it's distribution level?

MR. HAKE: Primary at the 12 kilovolts.

CHAIRMAN WEISENMILLER: Okay. And so you've been doing this under the Rule 21 process?

MR. HAKE: That's correct.

CHAIRMAN WEISENMILLER: Okay. And what were -- in terms of, you must have gotten some -- what was the biggest -- so you had the $1.3 million in cost, and also the five years in time -- what were the big elements in the time element and what was the biggest cost element when the interconnection equipment had to be done?

MR. HAKE: Well, in terms of the time element, I think -- I'm not sure that we can shorten the process if we're talking about taking a project through the whole lifecycle of design through construction, but I think where there was uncertainty between our contractor and ourselves in the utility was how to schedule certain inspections during the construction process. So it seemed sometimes difficult to us to get PG&E to be firm on certain dates when they could be available for inspection, and then, you know, with construction delays and everything, it's always this dance of trying to get things to align so that we could ensure that the inspection could proceed as scheduled. And then, in terms of the cost, I think one of the main elements there was we installed a direct transfer trip and, so, my understanding is that involved some additional communications that was needed in order for that trip to function, and so I think that was one of the main cost elements. About half of the cost was one time capital funding, and the other half of the cost is the ongoing O&M cost of like a one-time payment in perpetuity.

CHAIRMAN WEISENMILLER: And I was just going to make one observation and then I'll turn it over to Cliff in a second, is that there are companies that basically take on the role of scheduling coordinator for your type of situation, I don't know if there are any in the room, or certainly staff may be able to connect you with someone because it would be pretty daunting to go through the process to become a Scheduling Coordinator yourself, and obviously there are fees involved and various qualifications on those companies, but that may be the simplest route for you going forward.

MR. HAKE: Yes, thank you.

MR. RECHTSCHAFFEN: You said that the payback period has been lengthened because of the PUC's treatment of the RECs associated with the project, and I'm wondering what price did you assume the RECs would be sold at when you did the financing assumptions.

MR. HAKE: Well, to be clear, it's not solely because of the treatment of the RECs, I mean, the wholesale energy price decline is part of that, but --

MR. RECHTSCHAFFEN: Right, you said one of the factors.

MR. HAKE: -- but one of the factors is the RECs and so at the time we did the original cost calculations in 2007, we were thinking that we might receive a wholesale power -- we might receive a power price of between $.9 to $.13 a KW hour, including the REC, which I thought at the time was a conservative estimate, was about $.1 for a REC. And now we're seeing something much less than that, I think, for these unbundled RECs.

CHAIRMAN WEISENMILLER: Yeah, I was also going to note that the PUC has now proposed -- PUC staff EPIC, which would be sort of an ongoing renewable R&D program, and there are elements in that for biogas, and so certainly to the extent that East Bay MUD is supportive of those, I think that would help the PUC in certainly going forward.

MR. HAKE: Okay, thank you.

CHAIRMAN WEISENMILLER: Thank you. Any other questions from the audience?

MR. NEFF: Thank you, John. Next up is Bill Martini. Bill Martini is the Western Vice President of Sales for Tecogen. He is responsible for marketing Tecogen's ultra-efficient cogeneration and chiller product lines in California, but his territory also includes the Western U.S. and Canada, Mexico, and Asia. Bill represents Tecogen directly to hospitals, schools, and colleges, government buildings, and industrial facilities, performing detailed economic feasibility analyses for customers, and assists in managing their installations and long term service needs.

MR. MARTINI: Thank you, Bryan and Commissioners, and all the experts in the room. We are representing a smaller end of the spectrum -- in the ICF Study this morning you saw some analysis of commercial facilities typically under 500 KW, or under one MW.

This is a typical 100 KW type system, it's an engine in a box with fancy emissions controls, a generator, an inverter on the end, and so on. Basically, the numbers on the right show that, if you put 100 units of fuel in, you get a certain amount as electricity and a larger amount out as hot water, so the total efficiency when you're recovering all the available waste heat is about 82 percent on a higher heating value basis, or sometimes people use lower heating value when they talk about efficiency, which would be over 90 percent. This is what the systems look like, about the size of big desks. This is another one, that's in a Community College in the East Bay.

Typical applications are the nonprofit sector, so hospitals, schools and colleges, places that are residences, so that includes nursing homes, retirement residences, apartment buildings, condos, dorms, hotels. And then recreation facilities, so that could include athletic clubs, Ys, City pools, JCCs, and so on.

Basically, these are applied where all the energy can be used behind the meter, so we're not trying to sell electricity back to the grid, typically. All the heat is at the same time used for heating domestic hot water, space heating, or spas and Jacuzzis and swimming pools.

So when you do all that, the sweet spot, you can get a very high efficiency that, even though they're very small modules, no economies of scale going on here, they can be far superior in terms of overall efficiency compared to a combined cycle plant. That's where the greenhouse gas savings come from.

There's been a lot of technology advancement in the last few years and this is a picture of somebody in the room here, in fact, Bob Weisenmiller. Some of the things that have advanced the technology in the small end include different kinds of certifications for interconnection, we've got those for Europe, for New York State, California, nationwide, different all sorts of crazy certifications. In addition, this inverter-based micro-grid compatible module was developed in part with CEC support. There's some advanced engine work that's ongoing right now at the CEC and, then finally, extremely low emissions that are comparable to, say, a fuel cell, from an engine which is unusual, not what people normally perceive. And I think over time that mindset will shift.

But we appreciate the CEC's support and proud to say they're actually getting some royalties from their support, so….

A typical savings, you've seen this kind of graph before, but basically from the owner's perspective who puts this in, our systems are all privately financed out of capital budgets, school district budgets, they can save a third to even up to half for the energy that these systems make, they can save that much relative to the Base Case, which is just buying a bunch of electricity and a bunch of gas for their boilers from the utility. Obviously, it's because of the waste heat that makes that possible.

Similarly, the greenhouse gas savings -- and George from Itron alluded to this -- as long as you use the waste heat, that brown box there is the boiler gas use, the red box is the gas used at the PG&E power plant, and then the blue is the stuff that would instead be used onsite to make that same amount of energy. So there's good greenhouse gas savings potential as long as you're using the waste heat. If you look at, say, 100 units of ours in the Bay Area, and I know other manufacturers have similar systems, they're running about 90 percent of the time without any other means to dump the waste heat, except put it into the pool, or put it into the building for space heating. So these are real live efficiency calculations.

This is just a diagram that shows the current -- the emissions from an engine. On the right is traditional BACT, traditional emissions requirements for NO_x and CO. On the far left is what emissions look like from the newer systems, you'll be hearing more about this, I think, in the afternoon. In the middle are some published NO_x and CO numbers from fuel cells. So pretty similar, pretty similar.

I think one little pitch for smaller systems is that they can offer pretty good cost-effectiveness. There's not a huge SGIP incentive, there's not a huge capital outlay required by the site, we're kind of doing things the old-fashioned way here. And if you look at the amount of potential greenhouse gas reductions available from small engine CHP systems, you know, you get a lot of bang for the buck.

So I'm going to follow the questions that Bryan had sent us ahead of time that he wanted to be sure we all touched on. First, what motivates end users to put in these little things? Typically, a payback less than four years is going to be required. Right now, you'll still find some applications in that range and there are some brave folks who can tolerate a longer payback. But to have any kind of meaningful mass market, you're going to need a pretty good economic return. You obviously also need an excellent use of the energy onsite, so keeping the electricity on the customer side of the meter, not getting involved with the export as much as we think it would be handy at times, it doesn't look like the Regulations are going to be working out very positively for smaller projects, at least. Other things that influence owners' decisions, I think, is the level that they perceive of utility and government support. They want to be good citizens, they want to be good to the environment. If they can get a rebate check, whether it's $500 million or $5.00, it makes them feel better to feel like they're not fighting City Hall, so that's why I put it in italics. I think sometimes the levels of support -- symbolism is important here, too.

But they won't do a four-year payback if it's tough to implement, so what we found is that last item has kind of been one of the bigger challenges, and I'll be talking more about that.

Small CHP systems -- and I think, again, by "small" I'm referring to say under a megawatt system, and I think looking at ICF data of technical potential from earlier, it's about maybe a fifth or a quarter of the total 15,000 to 16,000 megawatts of technical potential out there. So the systems are small, but it's about a quarter of the projected technical potential that ICF was mentioning. So what happens in smaller projects is a lot of transaction costs per kilowatt hour, and these fees. And I just want to highlight the ones that I think have added a couple years to the payback.

These didn't necessarily exist 20 years ago, it's interesting to note. Departing Load Charges, what we also call Exit Fees, pretty much gobble up a penny and a half of the customer's benefit. So what you heard this morning about the customer trying to utilize energy behind the meter is only able to impact about half or two-thirds of the electric rate because of these sort of gotchas. Those Departing Load Charges, a customer who installs an energy efficient pump, or remembers to turn off the light switch every day, or puts in a solar system, they don't pay those Departing Load Charges, they have identical profiles as far as the PG&E meter is concerned, but they don't get whacked with these charges, so it's kind of -- it doesn't seem like a level playing field to us.

Similarly, with Standby Charges, customers who run following thermal load 95 percent of the time, that five or six percent of the time that they might be down because the pool is hot, is already up to temperature, we just thermally load follow, turn off, the customer pays a demand charge that month, but in addition, on that same kilowatt, has to pay a stand-by charge. And to us, that's something that other technologies don't have to pay. The underlying rationale that we've kind of accepted in California for years, I think, deserves a second look.

Interconnection is still a challenge. The new SGIP came out with a program for a very small rebate for engines and turbines. At the smaller sizes, the metering and monitoring requirements of that program, it appears to us, is going to consume half to the full amount of the incentive, which does take away a little bit of the fun. And so I think there needs to be some size differentiation. There are practical solutions that we've offered comments on and we're hopeful some of that will get fixed.

Net Energy Metering down at the bottom there is a benefit that a lot of DG technologies receive, but CHP does not qualify for Net Energy Metering, and we're not talking about the laws of thermodynamics here, this is just arbitrary Regulations. And that can be changed. And that would be a big help.

Rules are very complex. This is just a chart we received from a helpful utility that was showing us how the different types of charges might apply to different types of technologies -- megawatts, technology, when it was installed, what the fuel was, you name it. But I said it's about as simple as a third-world bus schedule.

Another side issue that the CEC in the past has been very helpful on was Rule 21. The CEC at one point, I think maybe for budget reasons, kind of considered that mission completed, mission accomplished, to coin a phrase, and that was then transferred to the PUC where there is now a pretty involved process going on that we're participating in when we have a spare moment.

One important thing that has kind of fallen off the back of the truck here is that CHP systems that are small need certifications to not get killed trying to put them in, not spending six months of your life on each project meeting with PG&E people. So a certification is an important thing. Smaller systems, there were a bunch of smaller systems that, in the earlier era, were certified under Rule 21, and that qualified them for what was called simplified interconnection. But that process doesn't exist anymore, so it's kind of Catch 22, the CEC maintains a list of certified inverters on its website, but that's only renewable certified inverters, as if the inverter knows the difference, as if the utility interconnection design team really -- the electrons are the same, whether there's an engine behind it, a turbine, or a solar panel. But you can't get certified. So we feel that we would like the CEC to allow non-renewable inverters to get certified the same way that they used to be able to.

I mentioned this just a little bit, but different technologies get all these special perks and the CHP seems to be coming up a little short on some of this stuff, and if the State wishes to have 6,500 megawatts of new CHP 20 years from now, leveling this playing field would be a real help. So I'll just whip through them, but there's exemptions for standby chargers, there's exemptions from departing load charges, there's eligibility for net energy metering, there's a practical feed in tariff that's not excessive and have a lot of ambiguous requirements for really small projects, interconnection fees that CHP has to pay that other technologies don't, and then finally, the SGIP incentives are really really quite different.

I'll just compare two DG technologies here. This is in both cases, it's a 100 kilowatt system consuming natural gas, it's got a natural gas meter parked next to it, both making very comparable NO_x emissions, so those are apples and apples up top, and then if you compare other qualities of the technologies, one has -- maybe is making just electricity without waste heat recovery, high efficiency, maybe around 49 percent depending on what math you're using, on the right would be a CHP technology where it's also recovering some waste heat. Both offer some greenhouse gas emissions reduction potential, depending on what you're assuming for the offset boiler and offset utility grid. Then there's the cost for the 100 kilowatt unit, maybe 130,000 on the right vs. 700,000 on the left. So those are like real numbers with the curtain pulled back.

Down below you'll see that they experience very different regulatory treatment. The technology on the left gets a much higher incentive, it's eligible for a big tax credit, as well, gets net energy metering, and exemptions from departing load standby, and so on. Small systems like ours don't get any tax credits, they're in nursing homes and hospitals, high schools, so I would say 99.9 percent of our systems don’t get any tax credits. But this is kind of a -- to us, the State is going to get what it incentivizes, but it won't get as much when it's paying a little more than it has to.

As a general rule, we would support creation of a level playing field and then letting the market sort of sort itself out. I think what's happened is people -- companies with good lobbyists have kind of gone directly to the Legislature and kind of worked out special deals. I see, having been an engineer in this business for over

20 years, I see more and more of our industry's time focused on selling things to Regulators and Legislators instead of doing actual energy engineering in people's basements. And I think that's kind of a loss for the State. I think what I call picking winners, I think a Legislator wants to have a nice green press release and a photo op, but it ends up being -- creating for some strange and confusing regulations.

I think the ultimate issue is that, for taxpayers and ratepayers, you want to deliver the most bang for the buck, and if you follow these sort of arbitrary preferences, sometimes you end up with an inefficient allocation of those resources.

So my conclusion would be just, over the long haul, I think we need to phase out these departing load charges that we don't see in other states and that we think really are unjustifiable relative to all the other technologies, efficiency technologies that customers look at, standby charges, net energy metering, it would be nice to have SGIP get a little more rational and be extended because it's probably going to go poof before a lot of projects are able to go in. Thank you very much. I'm available for questions after any time.

CHAIRMAN WEISENMILLER: Thanks. Again, let's talk about your experience on the interconnect, in terms of ways of trying to speed that up. Is the Rule 21 reforms going to do it all? Or how does that fit with certifying the inverters?

MR. MARTINI: I think the -- well, the Rule 21 reforms that are undergoing this settlement process thing at the PUC, which only companies, you know, it's two meetings a week, it's not practical for a lot of people -- there's been very little CHP participation in that, it's interesting. I don't think it's going to solve the issues that I brought up. The certification, thankfully, the certification provisions that were in there, that were hard fought under the CEC's supervision, under the former Rule 21 Working Group, the guts of that mostly is still going to be retained, there's still some -- many aspect of the simplified interconnection and that we're going to deal with just three paragraphs out of the whole bill, the whole new rule. But I think the main Rule 21 modifications are related to export systems and renewables, it seems like everything else is going to be kind of kept the same.

CHAIRMAN WEISENMILLER: Thanks a lot, Bill. Sure, go ahead.

MR. KUBBASEK: Thank you. Justin Kubbasek.

CHAIRMAN WEISENMILLER: Actually, if you have a question of him, otherwise we still have one more speaker.

MR. KUBBASEK: I do have a question for him.

CHAIRMAN WEISENMILLER: Okay, great.

MR. KUBBASEK: So in your experience, how aligned is customer payback with GHG reduction savings? I guess by that I mean the higher GHG reducing more optimal projects are also -- have a higher payback for their customers?

MR. MARTINI: I would say in general, yeah, that's true.

MR. KUBBASEK: Okay, so then I guess as a follow-up, I would be thinking, as we extend benefits or subsidies towards this market, then we shouldn't be looking at the most optimal projects, then, as representative of what we might expect by lowering or reducing the payback rate for projects that otherwise would be out of the money?

MR. MARTINI: I’m not sure I fully understand, but I think in general I would say you should look at how much benefit in terms of greenhouse gas reduction you can get for the investment. If the customer is going to do it anyway, then maybe you don't need to do much in the way of an incentive. But I think you want to -- but the reality is these extra fees right now are causing paybacks to be well over four years for a lot of smaller projects, and so you're not seeing a lot of activity, just a bare trickle.

MR. KUBBASEK: Thank you.

CHAIRMAN WEISENMILLER: Thanks.

MR. NEFF: Thank you, Bill. I forgot to mention earlier on East Bay Municipal Utility District's presentation, if anybody was interested in the wastewater treatment plant's potential in California that study is available online and the publication I.D. is on the bottom of that slide, Slide 6. I'm pretty sure Joe is happy to see his technology represented in that presentation.

Joe Allen is the Director of Government Relations at Solar Turbines, Incorporated. Mr. Allen is a Board member of the 2012 Chair of the Washington, D.C.-based U.S. Combined Heat and Power Association. He also sits on numerous other Boards, including the Board of the Business Council for Sustainable Energy, the American Uzbekistan Chamber of Commerce, and the Sustainable Development Advisory Board of the Rochester Institute of Technology.

MR. ALLEN: Good morning, everyone. And thank you very much, Commissioners, for inviting me, and thank you, Bryan. I'm going to keep this really short. I know we've got a lot of great information that's been presented. I'm very fortunate to be fourth on a panel of three other very qualified people, and you've heard some great summaries of the challenges that the marketplace is facing in CHP in California.

I want to take a minute first, most of you know Solar Turbines and who we are. As Bryan mentioned, East Bay MUD actually has one of our machines in operation there. But I think in the spirit of full disclosure, our name is always confusing when we're talking about the energy world. I spend half my time talking about what is a solar turbine and how do we get the sun to spin that thing. And the reality is we love the solar industry, but we aren't in the solar industry. The original company, we're based in San Diego, it was formed in the 1920's as the Prudden Bay San Diego Airplane Company, and then became Solar Aircraft. And that company didn't build planes very long, but it did have kind of a unique history of building the Lindbergh Plane. And that was built in the building if, when you land in San Diego and you see our facility at the end of the runway, that's where that plane was built and that's where our facilities are, our main manufacturing facility is today.

The company evolved into an industrial gas turbine company and was renamed Solar Turbines, maintaining the solar name and I was going to have a lottery on where did the solar come from, well, the solar came from the fact that it's sunny in San Diego, and they called it Solar Aircraft back in the late '20s. So that was the genesis, so we were solar before solar was popular, and we compare it to -- if you think of us as solar turbines, think of Apple Computers, they're not about apples and we're not about solar. They're about computers and we're about turbines. So that's for those that weren't familiar with some of the history, I wanted to just take a second and go through that.

Our company overview, we are natural gas and renewable fuel gas turbines. You saw a great example and a really nice presentation of a renewable fuel turbine, one of our Mercury 50s, at East Bay MUD today. We are a subsidiary of Caterpillar, we're wholly owned by Caterpillar, which is obviously -- I think a lot of you know who they are, they make the big yellow bulldozers and machines. A lot of people don't know that about a third of Caterpillar's overall portfolio is directed at the Energy industry in providing products that produce power, and with solar turbines being a big chunk of that. At Solar Turbines, we have around 7,500 employees with 4,000 of them in California, and we build all the turbines in California, so we're sort of a unique manufacturing entity these days. And we do export about 70 percent of our products out of the U.S. and, unfortunately, the ones that are in the U.S., not that many of them are going in in California, and some of that is because of some of the barriers that we're seeing. Our size range is in the one to 22 megawatt size, sort of our sweet spot is four to 15 megawatts is where you see most of our units going in. Key markets are power generation, but we also serve the oil and gas industry. We have global population of 14,000 units. Unfortunately, we don't have enough of those in California and we do have over almost a billion and a half operating hours.

I wanted to take a minute and, instead of going into specific case studies, etc., I wanted to really look at -- I'm trying to do a little summation on what customers are telling us and what we're seeing from a deployment standpoint related to California. And if you look at the base clean energy goals of the state, I put these four here, it's much more extensive than that, obviously, but obviously the key clean energy goals of the state align almost dead on with what the benefits that combined heat and power can provide. The big trick is, how do you get the regulatory regime and the markets in place to make sure that you have competitive markets delivering the right results to the ratepayers.

So to do this in a simple way, we just put together the report card. So if the customer is the parent and the student brings home the report card, this is sort of what they're telling us is happening, and again, this is not statistically valid data, this is fairly subjective in what we're hearing, so I did want to mention that, and I'll take just a second and go through each one of these to give just a little background. But the thing is, all of the items that you're going to hear have been discussed very well by the three panelists here, by ICF, and by others. The interesting thing is, there aren't a lot of unknowns in this whole discussion, and everybody involved in this, that the big trick is how do we get the policies right so that you have a marketplace that can function and deliver the results that the ratepayers are frankly asking for.

And if you look in the overall report card, a grade of C, clearly the customers don't see that as acceptable and I think the Governor would not see that as acceptable and would see that there's some opportunities to do much better, that it's been very clear the leadership of the State has said, "We're going to be the A+ state." And I think it's heading that way, we're starting to see significant signs, but right now I don't know that the state is there.

So, very quickly, if you look at a few of these items, AB 1613, that has been a very positive policy initiative and, frankly, just some good policy in how it was put together. Sizing systems with thermal load is logical. Being able to export if you have some excess makes sense. It took too long to do it and there are some other challenges in there, but I think overall what we're hearing and, you know, what we're seeing on the ground, that's the type of thing that adds value.

The SGIP, again, a very good program. You know, reinstate natural gas CHP, you know you're seeing our sales guys are saying they're starting to get interest that flat wasn't there before, so it is driving awareness again. There is, as we've heard, seems to be a preference towards advanced technologies vs. just greenhouse gas reduction. I think, you look at CHP as an industry doesn't want anything special, it just wants to make sure that there's a level playing field.

The last one here on no recognition of customer CHP value to the grid, you know, no recognition is probably too strong a wording, but it really is what we're hearing from customers is, hey, I'm on the customer side of the meter, I have these investments in place, and they do provide value, and they're a significant value from a capacity, reliability and grid congestion, and I really can't see -- it's not clear, or it's very convoluted how I get recognition for that. And I think there's -- from a policy standpoint, the state has some opportunities to be first in class in that area. And today I would say the customers don't think so.

AB 32, we've heard about that. I think the ICF report had some good detailed information. You know, in the Scoping Plan, CHP, the values, was recognized and it was very clear. In cap and trade, there's a lot of uncertainty on the final rule. Is it going to really reflect CHP value? And that actually -- that uncertainty is limiting deployment right now, you're going to make a big investment, and particularly if you have a site, you know, as an example, a site that may not have CHP today and they wouldn't be in cap and trade, and they're looking at making an investment that's going to throw them into cap and trade. They may look pretty hard at that, even if the initial financials may pencil out and they say, "What am I signing up to?" So I think, 1) clarity is needed and the final rule needs to be sure that CHP is appropriately reflected on the real value it provides for greenhouse gas mitigation.

Departing load charges, we've heard a lot about that. I think, you know, it's clear there's action needed there. As far as we know, California is the only state that has fairly onerous charges in this regard. When you look at -- I think there was an example if you do a lighting project to be more efficient and, you know, change your lighting, etc., you don't have a departing load charge; if you have CHP, you still have your departing load charge. You know, the bottom line is customer CHP on the customer side of the meter is energy efficiency and it's -- I think it's important to make sure that that's recognized and that the policies reflect that.

And the last one, and this one got an Incomplete. When you look at the RPS, and we've heard all the discussion this morning on the RPS, and from a positive point of view, you know, CHP provides documented benefits which complement the RPS, and when you put that on top of the fact of the leadership that, you know, in California saying, "Hey, we see the value in CHP, we want to deploy 6,500 megawatts," and then you look at the spaghetti bowl of things that have to be dealt with to try to actually deploy CHP, there's an opportunity for additional clarity to simplify this. And one -- and I'll throw this out as a bold goal -- would be for the State to consider some sort, I don't know what it would look like, and there's lots of folks that would have a lot of ideas and I'm sure good ideas, on some sort of a CHP Portfolio Standard. So if we're going to put 6,500 in, let's put in highly efficient CHP, do it in a fashion that clarifies where the State wants to go, set up the rules, and let's go. And that is, again, that's kind of a bold goal where you're asked, "Throw out -- what are the other ideas for the future?" And obviously, I don't think this is a new idea, I think this has been run around various times, but when you look at the realities today and where the State wants to go with its greenhouse gas profile, this is something that ought to be in the conversation again.

And to conclude, if you look at needed actions to advance CHP, what the customers are telling us, eliminate departing load charges for CHP, and we particularly see it in machines our size; recognize CHP's value in cap and trade, recognize CH value to the grid; and then consider the bold goal for highly efficient CHP, to have some sort of a CHP portfolio standard to really define it and have clarity to all parties, here is where the state is going to go, go and do a good job, and deploy it. And that’s what we're going to do. I thank you very much and I'd be open to questions.

CHAIRMAN WEISENMILLER: Thank you. Go ahead.

MR. TORRIBIO: Good morning. I'm Gerome Torribio with Southern California Edison and I'd just like to refer back to the report card. The grade of C for recognizing grid benefits, I wanted to ask you if you would consider appealing the grade and moving it up in light of the CHP settlement that's just become effective.

CHAIRMAN WEISENMILLER: Well, actually I had some specific questions for Edison on that very topic, so

I'm glad you stepped forward. Twenty-nine Palms, which is at the end of the line, there is a cogen project. You've had three outages at 29 Palms this month and it's adversely affecting training. What are you doing about it? And how are you incenting cogen there?

MR. TORRIBIO: If we've had an excessive number of outages, we certainly want to remedy that.

CHAIRMAN WEISENMILLER: Please do it fast.

MR. TORRIBIO: Yes. I think --

MR. ALLEN: To answer the gentleman's question, these are totally subjective direction from our customers and what we're hearing from the customer base, so I wouldn't know how to amend that grade, that's really the feeling on the street.

MR. TORRIBIO: Maybe you can help us with the outreach on that, then.

MR. ALLEN: Love to.

MR. TORRIBIO: Thank you.

MR. ALLEN: I think that's a really good point because I think the outreach and the overall, you know, I look at it and I look at this as the CHP community and I think the CHP community needs to continue to really look at how do we -- we get to focus on the goal and figure out, well, how do we get the policies in place to really deliver it and create a market system that works? You know, I keep hearing -- I've had it explained to me that, you know, CHP, if we're in a horse race, if that's the market, we've got a fast horse, but we've got a 100 lb. saddle, and we're asking our customers to say, "Give us the two pound saddle that the other horses are running with and let's see how it goes." And that's really, I think, what the whole CHP industry and community really needs to start to continue to focus on with the end in mind, is get to the finish line and deliver results that are really meeting the energy goals, in this case, the State of California.

MR. TORRIBIO: Thank you.

MR. TUTT: Good morning, Tim Tutt from SMUD and I just wanted to make a brief comment about the RPS Portfolio Standard vs. a CHP Portfolio Standard. As utilities in the state, we all procure energy, some imported, some in our service areas. So we all kind of face a level playing field of an RPS Portfolio Standard with the same options and, in general, where a CHP situation, we're looking at CHP potential within our service areas, and that varies significantly. So the same kind of structure doesn't fit quite as well to CHP in our opinion, as the RPS does for renewables. Thank you.

MR. NEFF: Thank you, Joe. I think the panel has tried to address most of these questions. Before I get started, I'm going to turn to the dais and see if anybody has any additional questions they would like to ask the panel as a whole.

MR. RECHTSCHAFFEN: I just want to know what my grade is and what Bob's grade is. We're on an incentive-based system here -- no, I thought it was very helpful.

CHAIRMAN WEISENMILLER: Yes, no, I think it's good.

MR. NEFF: All right. I have a couple additional questions. I think we did a pretty good job of talking about the first question and that the investors are really responding to the price signals that are there and the playing field that's been set out. I'd like to ask more specifically on the second bullet, what is the single-most difficult task you've had at installing your project, or, for the manufacturers, what is the single largest reason for project failure?

MR. RUARK: From Sonoma County's perspective, the delay in the project, the biggest delay was interconnection, getting interconnection agreement to be signed. And at this point, it's just getting the feed in tariff for the excess electricity put on the grid.

MR. ALLEN: Yeah, from Solar Turbine's perspective, that's what we seem to hear, too, is that interconnect is challenging just in how convoluted and the length of time and cost to do it.

MR. HAKE: I think I have already maybe talked enough about our interconnection issues, but in terms of the REC value, I would go back to that as being, you know, maybe a primary component in our decision to move forward with a project financially since we were self-financed.

MR. MARTINI: Since everyone else picked two things, I'm going to pick my two, would be the departing load charges and the lack of net energy metering for small CHP, I think that's been our biggest shortfall.

MR. NEFF: All right, moving to the third bullet, what can the State do to focus in on either a regulation that is existing and negatively affecting the CHP market, or a possible future regulation that will have a positive effect on the CHP market?

MR. RUARK: I love John's idea about a tiered structure for feed in tariffs based upon renewables. We have a fuel cell we could be using biogas in, however that cost, we don't have that capacity to pay the extra cost. But if the tiered structure was available, we might be able to buy biogas and make it economically viable.

MR. HAKE: Biogas requires quite a bit of conditioning, especially if it's going to be used in a fuel cell, so there would be a lot of additional cost for that, so that's definitely a factor.

MR. ALLEN: I think one of the more near term actions that could be taken is, you know, SGIP because that program is a successful program and the fact that these technologies are back in is to provide a little more certainty on the length and consider extending that program out beyond the 2016 and, you know, continue to look at leveling it a little bit from an incentive standpoint so that there's a little more balance in the incentives that are going to be provided, if they're leveled a little bit more between the technologies.

MR. NEFF: Is there anybody from the audience that has questions? Anybody online? No questions online. Well, thank you panelists. Thank you for your contribution and I'll be moving on to some Industrial CHP issues. We have two presenters left before lunch, so we're going to try and get to those right away.

The next presenter is Dr. Barbara Barkovich. She is was a consultant and expert witness on energy and regulatory matters, including marginal costs, cost allocation, and rate design, electric industry restructuring, and electric resources analysis. Dr. Barkovich is Chairperson on the Board of Restructuring California Power Exchange. She has also served on the California Independent System Operator Governing Board and the Energy Engineering Board of the National Research

Council. She has previously worked for the CPUC, ending up as director of Policy and Planning.

DR. BARKOVICH: Well, I'm going to try to be brief to not get in between you and your lunch. And actually a number of things that I'm going to talk about have been mentioned before, but I'm going to attempt to bring a perspective of customers who have the potential for bottoming cycle CHP, which is the kind of CHP that almost always gets forgotten, and also customers who are maybe bigger than the small CHP, but smaller than the big CHP, sort of Mama Bear sized CHP, and also customers whose focus is onsite usage for which things like 1613, etc., don't really make much difference.

So bottoming cycle CHP basically, for those of you who don't know what it is, you basically have an industrial process that has fuel that comes in and is a high temperature process. And at the end of that process, you've done whatever you've done, made clinker in a cement plant, melted glass or something, and you've got waste heat. You can do a number of those things with waste heat. But one of the things you can do with it, or part of it, is to make electricity. You can make electricity using that waste heat without any supplemental addition of heat, in which case it's basically pure bottoming cycle CHP and has the equivalent of an infinite efficiency.

That is, electricity with no fuel input because the fuel has already gone into the industrial process and would have gone in there regardless of whether you made electricity or not. And this is something that was recognized by the Energy Commission in its AB 1613 Regulations for defining the Electrical Efficiency Standard for Bottoming Cycle vs. Topping Cycle CHP. That is a distinct attribute of bottoming cycle CHP.

The other thing about bottoming cycle CHP is it is very industry and facility specific, and this relates to the nature of the process that creates the waste heat, if it's an existing facility it has to do with the configuration, the space available to put the waste heat recovery system in, etc.

So the experience, at least of my members, has been that when you get an indicative bid, it looks like it could be a really good fit for you, and by the time that they give you the full bid package, it costs three times as much and doesn't make any sense anymore.

So to finish my summarizing of bottoming cycle CHP, it doesn't tend to -- I mentioned onsite usage -- one of the reasons for onsite usage is that, for an average industrial facility, the part of the process that produces the waste heat is only a fraction of the total industrial process, therefore the electricity that you could make using the waste heat tends to be less than your entire load. So it's not an issue of producing so much you want to export it because you have an excess of your needs, and the economics are such, as well as the hassle factor is such, that using it onsite in many ways makes more sense than trying to export everything and buy your power from the grid or from, you know, through some other supplier.

The other thing is that there really are very few incentives available as has been pointed out. The SGIP incentives, which now are available once again for CHP, also include a line item which is called Rankine Cycle, which we believe was the PUC's attempt to refer to bottoming cycle, even though that's not the only potential bottoming cycle technology, but you have a set of incentives that you get the full incentive for the first megawatt, half the incentive for the next megawatt, and half the incentive for the next megawatt. Well, if you're a three megawatt project, that might look pretty good, but given that the size of a project is going to be totally a function of the amount of waste heat and the source of the waste heat at the customer premises, at least for a cement plant, a bottoming cycle project might be eight to 10 megawatts, so you really are only getting a declining incentive on the first three megawatts, and this is part of what I believe is a longstanding bias in California against things that are bigger than large bread boxes, so that, as we know, things under five megawatts are always better than things above five megawatts, and in the case of the SGIP, things under three megawatts are obviously better than things bigger than three megawatts. And the reasoning always is, "Well, we only have so much money and we have to spread it around." But the reality of the situation is that there are lost opportunities because larger customers can never get equivalent benefits to smaller customers -- the issue of economies of scale, notwithstanding.

All right, I'm supposed to be doing slides, right? Okay, sorry about that. I'm caught up now. Tradeoffs with energy efficiency in terms of the heat available, several speakers have made the point that CHP is energy efficiency. In the case of bottoming cycle CHP, as I said, what happens? You put the fuel into the industrial process, you do whatever you're going to do in the industrial process, and you get the waste heat out. Then you have choices about what to do with the waste heat. The preference has been policy-wise to do all cost-effective energy efficiency first, and traditionally that's what industrial consumers do. For example, in a cement plant, you will take that waste heat and you will use it to preheat the input to the kiln, you don't waste the energy. But the more energy efficiency you do, the lower the grade of the heat is to make the electricity. And so, if you "exhaust all cost-effective energy efficiency first," depending on how you define cost-effective, you can be in a situation where the quality of the waste heat that's left doesn't produce very much electricity. And because of the policy of doing all cost-effective EE first, there's no co-optimization with electricity production. I mean, that has just simply not historically been considered. And for a while, when there was no SGIP funding available for CHP, maybe it didn't matter so much. And certainly the Energy Commission Standards for AB 1613 specifically discuss doing energy efficiency first. But there does need to be an understanding that there's a tradeoff there.

And then, as I said before, and this has been said as well, bottoming cycle CHP without supplemental firing is effectively energy efficiency; you're taking waste heat, you're turning it into electricity. And as I mentioned before, a lot of these projects with respect to industrial facilities are going to be in the three to 20 megawatt range. So they're going to be less than 20 megawatts, but they're going to be bigger than the small cogen you've been listening to discussion about.

Supplemental Firing. One of the things you can do is to add some additional heat into the process before you convert the waste heat to electricity. And that's called Supplemental Firing. It does involve some GHG because supplemental firing is normally done with something like natural gas, but it can significantly increase the output. And one of the things that we demonstrated as part of the Energy Commission's rules for AB 1613 is that there are -- you can have a significant level of supplemental firing and still, on an electrical efficiency basis, an emission basis, be better than a new combined cycle power plant, which is the reason why the electrical efficiency requirement for bottoming vs. topping cycle under AB 1613 is different -- has to do with going through all the chemical engineering calculations. But the analysis can be done and has been done by your staff.

This point has been made and I'm delighted it's been made so I can make it relatively briefly. Without supplemental firing, bottoming cycle CHP is pure energy efficiency. But, if you do something to your facility -- improve your lighting, putting variable speed drives, whatever, improve your efficiency, reduce your usage, you don't get departing load charges. You put in bottoming cycle CHP in and you get departing load charges. It doesn't seem quite equivalent.

Customers using CHP do not have to pay the CTC, the Competition Transition Charge, which is amazingly still around since 1995, even though the reason for it might have gone away, but that, at least for that 3,000 megawatts, but they do have to pay for the PGC, what was the PGC, that's the low income program, it's the energy efficiency program, what is now called the EPIC, and DWR Bond charges, and this slide forgot nuclear decommissioning because I put this together in about three seconds. Again, those charges would not apply if you had a load reduction due to EE.

Cap and Trade. We've heard some discussion about this, as well, that's the advantage of Mr. Silva and me batting clean-up. The utilities receive free allowances from CARB, are going to based on historical load. That historical load includes the load of customers who currently do not have CHP, but might choose to install CHP in the future, so that if those customers had not existed, that utility share of the free allowances would be smaller. If that customer doesn't have CHP and adds CHP, and the utility does not allow some of that CHP value to go to the customer adding CHP -- I'm sorry, cap and trade value to go to the customer adding CHP -- then the utility ends up with more allowances and less load. The customer who departs, on the other hand, now if it has onsite CHP and does have -- let's say there's supplemental firing for bottoming cycle where it's a topping cycle situation, they now have an additional cap and trade obligation for GHG associated with their onsite generation that didn't exist before. If they're EITE, it's not in their baseline because they didn't have it when the baseline was calculated, so the utility and the remaining utility customers basically get relatively more and that customer gets a relative disincentive because, if it stayed with the utility, it would be able to keep that share of the allowance value, whatever share the Public Utilities Commission ends up deciding to give it. So, there seems to be an equity issue here if you're trying to create an incentive for new CHP for existing customers. Probably enough said. And that's it.

CHAIRMAN WEISENMILLER: Thanks, Barbara. I was going to circle back on the cap and trade issue and ask if you have specific proposals on how the utilities could share that credit with potential CHP project.

DR. BARKOVICH: Indeed, we do. We actually submitted comments at the Public Utilities Commission on this point and made the argument that if an existing utility customer, agreed customer, were to subsequently engage in onsite CHP that they would have allowance portability. That is that they would be able to take either -- if the allowance were monetized, they would be able to get some credit on their bill that would be the equivalent of what they would have gotten if they'd stayed as a bundled customer, and if they were actually -- if the Commission -- if CARB changed the rules that the Commission could actually give customers allowances, as opposed to giving customers allowance value -- monetized allowance value -- that the customer could take allowances. And we believed, and this -- we could send them to you, I mean, this is all in the PUC record, but we believe that this would not disadvantage the remaining customers because those original allowances were predicated on that load continuing to be with the utility.

MR. RECHTSCHAFFEN: So when you say the equivalent share that the utilities would have received, you're sort of doing a pro rata share of the allowances they get based on the load that was on the system before the CHP System was installed?

DR. BARKOVICH: Right, and Ray is undoubtedly going to tell you why this can't be done, but that is our recommendation at the PUC.

CHAIRMAN WEISENMILLER: Okay, could you also submit that in our docket?

DR. BARKOVICH: Oh, sure.

CHAIR WEISENNMILLER: Thanks. Ray.

MR. WILLIAMS: I just wanted to address this issue. The way that the allowance allocation was set for the utilities was based partially on load, partially on historic emissions, and partially recognition as to how well various utilities did in terms of energy efficiency in RPS in terms of promoting clean generation. And then it's fixed and the reason that it's fixed is, over time, you didn't want a utility to get more allowances, by increased emissions to get more allowances, it's a bad signal. So that's the way it was set initially. Now, moving to the PUC, all utilities pledged that the revenues that we received through the auctions, which is what the IOUs have to do, or the allowances directly, which is what the PUCs have available to them, go back to customers. None of them go back to utility shareholders, so we need to be really clear about that.

So then this becomes an allocation issue for the benefit of utility customers, okay? And what Barbara is talking about is a situation where load goes down because CHP is installed. You know, for a particular customer, their allocation will depend on essentially the amount of electricity they buy from the utility. So, I mean, the converse to that, you could say if you're looking at an individual customer, is if a customer no longer has a CHP because they lose their steam host, they will receive more allowances presumably because they will be buying more electricity from the utility, so there's two sides to that.

Now, I'm going to go to a place where I don't know much, but I think it's worth investigating. And that is, as part of the industrial sector allocation, it's based on energy intensive, trade exposed criteria and it's sort of benchmarked, and I believe the amount is actually updated from time to time because you really have to track the individual industrial customers' circumstances. That is a place in that updating that circumstances change with respect to CHP, whether they're installing more CHP, or less. It's another place to go to try to make a CHP customer (inaudible). I understand that it does, you know, that they will have a compliance obligation if they're above a certain threshold and that's maybe a place to address that, as those circumstances change. But I’m really at the end of my knowledge in terms of how the industrial sector allocation works.

DR. BARKOVICH: I think it's possible you're beyond your knowledge in terms of the updating, but we may be able to clarify that. I know Evie calls here and she knows those Regs even better than I do, and I've spent more time on this than I want to, but I'm not -- I mean, my understanding is that, for EIT -- first of all, we've got both EITE and non-EITE customers who can do CHP. For EITE customers, their allowances are based on historical baseline. And for non-EITE customers, yes, they weren't given any allowances by CARB because they weren't EITE, and if they install CHP and leave the utility, they're going to lose the reimbursement from the free allowances that they would have gotten if they'd stayed with the utility. So I still think it's a valid point.

MS. KAHL: And I agree with Barbara, right, that when a customer -- the only way you can get an increase in your greenhouse gas allocation from CARB if you're EITE is if your output changes. And so a shift in your electricity source doesn't generate more greenhouse gas allowances for you, so that's not --

DR. BARKOVICH: Mic, mic.

MS. KAHL: I'm sorry, I'm Evelyn Kahl.

MR. RECHTSCHAFFEN: And then there's the whole sector that doesn't get allowances at all because they're too small and they're not directly regulated under AB 32. The panel we had before that these issues are raised in a very salient way with, as well.

DR. BARKOVICH: Right, this would definitely apply to them because they don't get any allowances, period. And as somebody said, in order -- putting in CHP would put them over the 25,000 mark and require them to be subject to cap and trade, they might think twice about it -- I believe somebody said that -- because it does add a level of complexity to your life.

CHAIRMAN WEISENMILLER: Okay. Thanks, Barbara.

MR. NEFF: Thank you, Barbara.

CHAIRMAN WEISENMILLER: Good to see you again.

DR. BARKOVICH: We went to school together.

CHAIRMAN WEISENMILLER: We did.

MR. NEFF: Next up is Tom Silva. Tom Silva is the Power Policy Manager for California within the power advocacy and commercial solutions group for Chevron's Global Power Company. Mr. Silva provides regulatory and power advocacy support for Chevron's upstream and downstream California assets, specializing in power, gas, and electric utility and state regulatory issues. Prior to joining Chevron as a consultant, Mr. Silva enjoyed a 28-year career with Pacific Gas & Electric, most recently serving as Senior Corporate Account Executive in Corporate Services and Sales as lead for PG&E's Oil and Gas Industry Business Segment.

MR. SILVA: Thank you very much. I'm thankful for the opportunity to present Chevron's view on CHP and to provide a perspective on the industrial application of CHP and illustrate how Chevron has embraced CHP technology.

As we are all aware, current California legislation strongly supports energy efficiency and greenhouse gas emission reductions, and CHP is a critical component of California's Climate Change Initiative. Yet, when industry seeks to employ energy efficiency measures with a byproduct of power, it is faced with a number of barriers to implementation.

I'd like to give you a little perspective on Chevron and CHP. Chevron embraces energy efficiency. Every manager is empowered to engage energy efficiency wherever possible. And we have been employing CHP technology in California operations for over 25 years. We have a long history of utilizing CHP in industrial applications with over 50 units representing 1,140 megawatts embedded in California refineries, oil and gas operations, and in our joint venture power facilities that supply power to our energy intensive operations and it eases the load on the power grid. Chevron is one of the larger power consumers in the State of California, as well as one of the largest industrial users of CHP power generation.

In our San Joaquin Valley operation, Chevron engages in enhanced oil recovery activities and we extract oil products during those operations. Due to location and existing utility resources, Chevron has installed our own electric distribution grids and one of the main purposes for this is to ensure reliability. We utilize boilers in CHP generation to power our equipment and to facilitate the extraction process.

Chevron is typically interconnected to the electric utility grid through transmission substations. These substations often serve as the point of common coupling to the CAISO controlled grid. Now, at Cymric, we have the opportunity to employ energy efficiency and to test the new technology, the bottoming cycle CHP that mines waste heat that we inject and then recover through a proprietary process. Cymric is a one megawatt bottoming cycle CHP technology pilot that produces the following benefits: energy efficiency, waste heat recovery, high reliability, energy production without additional combustion, and we reduce greenhouse gas emissions, thereby reducing greenhouse gas emissions. Our project aligns favorably with California standards for efficiency in emissions. This is a new technology that is viable. If piloted successfully, we can deploy this technology across our oil fields and at our refineries.

At this point, the technology has not been implemented because of the barriers we have faced and the challenges of small non-merchant CHP application sees in the marketplace. While Chevron had initial plans to install 50 MW within California, we have now been forced to reduce our roll-out to less than half of what we had originally planned, and all of this is a result of the experiences we've had from this pilot project.

What you see now is a simplified timeline that addresses the parallel paths of AB 1613 legislation and Chevron's experience with its Cymric pilot project. As you can see by the timeline, AB 1613 legislation was enacted in 2007, but final approved contracts were not made available to CHP customers until the very end of December in 2011. The delay in outcome and implementation created a great amount of uncertainty and created additional expense to Chevron.

A key point here is that we were required to go through two different Rule 21 application processes with PG&E. Our engineers had originally endeavored to install a three megawatt pilot project behind an existing point of common coupling, behind CHP that we had in the field. We were told by PG&E that we could not install the unit at that location, and so therefore we had to redesign the project on a smaller scale and reapply for a new Rule 21 application. And now, at the end, as you can see down in December -- or in October of 2011, Chevron was told by PG&E that we would now have to file the PG&E Wholesale Distribution Access Tariff and that would put us into the more costly CAISO Independent Study process and it would require additional expense.

From mid-2008 when Chevron first brought the project to PG&E, through late 2011, we have suffered critical time delays that have threatened the very implementation of this project. Although a more streamlined process is available, we have come to understand that there have been no Greenfield fast track applications cleared by PG&E.

We're all aware that California is the leader in energy efficiency in the United States, yet if you place a turbine behind a pure energy efficiency project, you face significant burdens. And those delays lead to a lost benefit in greenhouse gas emission reductions, energy efficiency, and increased cost to developers of the projects. CHP is an important capital investment for Chevron, but the entire process often makes it untenable.

We understand that Regulations are enacted to promote the development of efficient CHP, yet the delay in AB 1613's implementation created a great amount of uncertainty for small CHP development in California. Instead of supporting CHP, in practice the process has gotten in the way. For example, over the last two years, I believe there were almost 10 different filings by the utilities questioning the validity of AB 1613 legislation, and these including petitions, advice filings, and requests for re-hearings; all of these impacted our project.

So what are the three challenges that we've seen at our Cymric project? First, there's the threat to existing CHP, and some of you have addressed this. I have to admit, we have a really good contract at Cymric right now, a very good Power Purchase Agreement. We have existing CHP in our oil field there. Yet, if we installed our project behind the point of common coupling, we were told by PG&E that they would cancel the Evergreen Contract. And so, as a result, it forced us to reevaluate our project. We had to reconnect at a new point of common coupling, we had to rescale the project and relocate the site. We have to install new distribution level interconnection facilities. And now, as a result of all of this, we will now have power sales onto the grid because we were told by PG&E that we could not utilize the power produced in this pilot project at the site. As a result of that, we are now engaging in an AB 1613 Power Purchase Agreement for those sales onto the grid. But it doesn't stop there. We are no longer eligible for the self-gen incentive program for this waste heat recovery project because, with no host for our generation, we become ineligible under the SGIP requirements because we are now selling more than 20 percent of our power onto the grid.

So the second barrier we encountered was the interconnection process, itself. PG&E was very helpful in offering us alternative sites for interconnection, but that required reengineering from our Chevron resources, both for the project and the time delays in getting this done. Now we're required to have a new System Impact Study for the new point of common coupling.

As we move from the Rule 21 application process into the PG&E wholesale distribution access tariff process, which is, by the way, much more complex, it is much more costly. The Rule 21 application was $800.00. The WDT process requires a $50,000 deposit. Now, if we had rolled out the original project with 40 different installations that we've identified, that would be a considerable expense for Chevron.

We are also engaged in the lengthy CAISO Independent Study process and all of this for a one megawatt distribution level interconnection? And then, finally, our point -- our bottoming cycle project is not a wholesale generator, and I think we've heard everyone else talk about that today, but yet our one megawatt pilot is basically viewed in the same way that a wholesale generator would be with regard to the interconnection process. And instead of being seen, as Barbara stated, as a pure energy efficiency measure, we're really viewed as a wholesale generator in the process. We had no desire to sell power when we engaged in this project in the first place.

We believe there should be a differentiation in the regulatory treatment for industrial processes and applications that deliver small amounts of as available power onto the grid vs. true merchant generator applications. We are not wholesale generators and we believe projects like ours should be treated differently.

In addition, the attempt to impose resource adequacy or full capacity deliverability status should never apply to these types of projects. They are not curtailable. And if it had been approved, it would have made our project impossible to implement. This is a very small project, it has been subjected to a number of delays, applicable more to a transmission level merchant generator than this internal industrial process application should have required.

So what can we do to encourage CHP in California? We believe that the current regulatory environment has created uncertainty in the market. As I exhibited on the timeline earlier, implementation or timely implementation is critical. When we conducted our analysis at Chevron, we first initiated this project, I believe, in 2008 in our internal discussions, and a good question was how would we be governed at the end of the day. Chevron would also like to see a clear path forward for implementing new technologies like this on a much broader scale.

And I do want to mention that the utility partners and the regulatory agencies were very helpful in ushering us through the process, but essentially they threw up their arms and said, "You know, I know this doesn't make a lot of sense, but it is the process we're forced to live under, and therefore this the way we have to go." So we would like to see a much more streamlined process in the future.

And I don't think anyone has mentioned it today, but small CHP is still faced with the generation behind the generation problem, this is behind the point of common coupling. We have identified a number of opportunities for application of this type of technology, a location served by existing CHP and existing Power Purchase Agreements. In order to preserve the PPAs, do we really have to interconnect at a different point of common coupling, all when the power is consumed onsite? So, for many of our applications, CHP is used as an energy efficiency measure. Power generation is simply a byproduct of the process. We typically size our CHP and our industrial applications to meet our steam needs, so there may always be a potential or some excess power onto the grid. Actually, in a perfect world Chevron would like to be able to use power generated on one site and flow it to another, but I know that will be a challenge.

As has been stated before, Chevron also disagrees with the current application of departing load charges. They should at least have a date certain end. We question the applicability of these charges for this type of project. We wonder if the utility is ever considered, the load we generate behind the point of common coupling, in their long range plans.

So in closing, because of our experiences within the current environment and the time consuming interconnection process, Chevron has scaled back its efforts to install new CHP in California. We will no longer consider sites governed by existing PPAs and will only consider employing energy efficiency and greenhouse gas mitigation technology at Greenfield installations in the future, that is, unless regulations change. So thank you very much.

CHAIRMAN WEISENMILLER: Thank you. Actually, I was going to point out that, when I worked with Chevron on the Richmond Cogen Project, it turned out there was a cogen facility there since the '30s that was shut down eventually when the current project came online. So your history is even a little further than you think.

MR. SILVA: Okay, thank you.

CHAIRMAN WEISENMILLER: Thank you. A couple questions. I guess one, for the PUC, in terms of -- is the definition of Rankine -- was that the intent to cover bottoming cycle? Or do we need some clarification there? Or do you need more time to think about that?

MS. KALAFUT: I would have to check with our SGIP Program staff about the intent behind the organic Rankine cycle definition in the rule, but my guess would be that the intent was for bottoming cycle, not just Rankine cycle.

CHAIRMAN WEISENMILLER: Yeah, that would be my guess. If you could clarify that for the record, that would be great.

MS. KALAFUT: Okay.

CHAIRMAN WEISENMILLER: So, in terms of the sorry saga at Chevron, I guess, Dennis, is there a way from the ISO to get them out of the WDAT process? I'd ask the same question, obviously, to Ray.

MR. PETERS: Good afternoon. Dennis Peters with the California ISO. Well, I really can't comment on --

CHAIRMAN WEISENMILLER: The specifics, I know.

MR. PETERS: -- well, specifically on why they were required to go underneath PG&E's wholesale distribution tariff. With regard to how the ISO's involved in that, WDT, or WDAT projects for the other two utilities, they do find their way into our base cases for our generator interconnection process. So I wouldn't be able to comment on why it was moved from Rule 21 to the WDT, I guess PG&E would have to comment on that.

CHAIRMAN WEISENMILLER: Yeah. But, I mean, my presumption is that, if there is anything the ISO can do to help move along bottoming cycle within your tariffs, you should try to do that.

MR. PETERS: Yeah.

CHAIRMAN WEISENMILLER: Ray, again, I don't know if you really have the background on this specific -- if you guys want to comment on that later, but this is not a happy story.

MR. WILLIAMS: Yeah, I don't spend a lot of time on interconnection. The one thing I was going to point out later is that, as part of the QF CHP Program, we do recognize that generators have a lot of obligations; they come in part from the QF CHP Settlement and they come in part from signing a contract of some sort which puts them into an interconnection process of some sort. We did try to sort out, based on your situation, where it was that you needed to go, and we presented that to the QS, but it's not the -- we tried to make it as clear as we could it's not simple and clearly -- you know, we're working on Rule 21, the settlement discussions as was determined -- talked about early, so that's at least one element of moving the interconnection process along more smoothly.

CHAIRMAN WEISENMILLER: Yeah, it seemed like this one is certainly -- if you could sit down with Chevron and try to work through some of these things and get back to us, again, it's sort of -- as we know, the interconnection processes are complicated, but having to go from one to the other just seems like, you know, incredible difficulties being presented, or being put in the way of getting these projects done.

MR. WILLIAMS: I'll talk with Tom and find the right people, and I think it's on the Electric Transmission side, and see if I can get them connected.

CHAIRMAN WEISENMILLER: Okay, great. Thanks.

MR. SILVA: Well, for the record, the project is moving forward and PG&E has been ushering us. I think what we were dealing with was the front end process there, you know, would like to see a way where we could install this technology and not violate existing contracts. You know, we're looking at reliability of our operations and energy efficiency and we think that something as simple as check meters or agreements with -- or amendments to the existing Evergreen Agreement would be sufficient in many cases, but to force us through the process we went through is pretty cumbersome.

CHAIRMAN WEISENMILLER: Well, again, I think certainly for the Commission's and for PG&E and Edison, energy efficiency is at the top of the loading order, so trying to figure out ways to achieve these benefits, you know, it would make sense for everyone to work together on it. Okay, any other questions for either Dr. Barkovich -- sure.

MR. BROWN: Good morning, it's Andy Brown from Ellison, Schneider and Harris. I've been asked to come down on behalf of Praxair Plane Field. They're an industrial gas producer. The process there is very energy intensive. And they have a situation where I think it's touching on some of the stuff that Dr. Barkovich addressed with respect to the impacts of the CARB GHG Program. Specifically, they have a production site that's in Southern California on the border of LADWP and Edison, and they are, in light of some upcoming retail rate increases, looking at restarting an existing CHP that they have that has been turned off because they were able for a period of time to have some rates that made it beneficial not to operate the cogen. The problem that they're seeing is the one where, if they operate the cogen, they'll now carry a GHG compliance cost which doesn't obviously exist on them as a grid connect customer. But at the same time, they're not going to get a flow back of any of the auction revenues if they are no longer taking from the grid. So the grid connected customer has an offset if you do go to operate a cogen, as mostly just to serve your own load, you actually are facing a disincentive because you don't have any of those offsetting revenues.

Additionally, because the project is on that border, there isn't a parity of the rules at CARB between the handling of GHG allocation offsets by POUs vs. IOUs, and so that also creates a bit of a conundrum there. And so this is, in essence, a barrier issue in terms of an application of cogen at an industrial site that, you know, probably could make sense in light of the rate increases that are anticipated to come in large part because of RPS, among other things.

CHAIRMAN WEISENMILLER: That's good. Certainly, again, if you have specific suggestions on how to move forward, it would be great if you could submit those to the record.

MR. BROWN: Yeah, I think we're going to be looking at presenting those in the written comments.

CHAIRMAN WEISENMILLER: That would be good.

MR. BROWN: Thank you.

MR. NEFF: Do you have any more questions?

CHAIRMAN WEISENMILLER: No.

MR. NEFF: All right, well I think we've reached our lunch break. Thank you, Barbara and Tom, for presenting. We'll be returning in an hour --

CHAIRMAN WEISENMILLER: Actually at 1:30.

MR. NEFF: So 1:30, just shy of an hour from lunch to conclude the rest of our day's events. So thank you, all presenters who presented this morning, and we'll see you after lunch.

(Recess at 12:35 p.m.)

(Reconvene at 1:37 p.m.)

MS. KOROSEC: All right, if you'll take your seats, we'll go ahead and get started again. I'll pinch hit for Bryan here, I think he's taking care of some last minute business.

We'll start back with the topic of Innovative Financing for CHP Development and our first speaker is Tom Casten from Recycle Energy Development, who is a member of ACORE.

MR. CASTEN: Thank you very much for the -- can you hear me? Am I good? Thanks for the opportunity. I'm going to very quickly review what I think is good to encourage CHP, talk about some problem areas, explain some added values very quickly that I think justify more time, and then make some suggestions. But in order to do that, I thought I needed to tell you about my dog. I got this wonderful Australian Sheppard, one-year-old, his name is Guido, he's intelligent and he's lovable and he's full of energy, and he and I kind of have a war going on, I put up a fence, he finds a hole; I fix the hole, he finds another hole; I get all the holes fixed, he finds he can jump up on a five-foot wall and pursue his self-interest which is to leave the yard. I put a fence up and finally we get that taken care of, I put him on a leash, go down to the bakery, go in and get my coffee, come out, he's chewed the leash free and is going again. I think I just described the last 80 years of utility regulatory regulation. And the paradigm that I'm going to express this in is that we made a Faustian bargain 80 years ago, the goal of the last century was to provide reliable electric service to all the population. We achieved that goal, we did it in a way that said we'll give you monopoly control over everything, we'll guarantee your profits, you don't have to face competition, but we're going to regulate you. And what I've heard all morning and, unfortunately, what I've heard for the 35 years that I've been in this business so far, is that there is absolutely nothing that the utilities perceive to be in their self-interest of putting in distributed generation, quite the contrary. And they drag their feet and they do it out of self interest. And it's not that they're immoral or anything else, it's just that the self-interests aren't aligned. And so my suggestion is that the future is going to be described by a word that starts with "D" and it'll either be distributed generation, or it will be disaster. And I don't think there's any other words.

Why I say that is that the CO_2 comes 69 percent from making heat and making power, and as long as we continue to do that with two fires, we throw away two-thirds of the energy making the electricity, and then we throw away all the work on the other thing. The only way we can do that with one fire is to have distributed generation, good quality CHP and, most importantly, waste energy recovery which was not covered in the options this morning and probably adds 1,500 megawatts to what you saw.

So with that in mind, I'll try and give some quick comments here. The good -- the goal of another 6,500 MW, terrific, in removing the Settlement issue, that's been blocking everything for four or five years and I'm glad to see it. The Self Generation Incentive Program has a real opportunity to start something bigger in California. The sub-five megawatt range has always been a challenge to developers because there's so much transaction cost and so much difficulty and, if you add any transaction cost to it at all, you kill the deal and it's chicken and egg because you never get enough of it going that we start to overcome all of the lessons and get better at it. And so I think your SGIP might break that chicken and egg cycle, I would be surprised not to see some developers -- we are coming at it hard with our back pressure steam turbine division making some significant commitments, and I think that's helpful.

The feed in tariff removes a lot of the uncertainty for hosts, it takes us anywhere from one year to three years from the time we first knock on a door of a host, before we reach a contract. And you don't want to spend all that money doing that if you don't know at the end of the day that you can get a contractor that's going to be worthwhile. So I think that's the good.

Problems. And the problem is that we haven't figured out how to train Guido with a carrot; we try to control Guido with a stick and utilities very intelligently employ floors and floors of people to figure out how to find another hole in the fence, and how to slow things down that they don't want to do, and what's not in their self-interest.

The standard interconnection process seems to be broken. It's always been raised as a technical issue, it's not, it's a commercial issue, not that you don't have to think about it, but it's a commercial issue. Now they push off to the ISO who doesn't think they have any customers and can take up to five years to figure out whether you're going to have transmission. The utility says that's great, it'll stall this project for another five years and we'll go from there. There's a number of grid benefits that CHP can produce and I'm going to talk about them, but they're ignored by everybody and, if I leave you a second message besides the paradigm switch, it's let's look at some of these benefits and see if we can't capture them.

The CARB deliberations have really put a chill on things. I'm going to be perfectly blunt, I think that the proposal to cut everybody to zero emissions and then charge everybody and spread the money around later is just a bad paradigm. It would be so easy to fix by giving everybody the average and, if you're cleaner on an output basis, you've got things to sell; if you're dirtier, you've got things to buy, and the market will clear. But we've created lots and lots of problems, and the hosts that we're talking to say, "I don't want to proceed with this because the way I'm reading the rules, I might have to pay more for carbon if I do the right thing. If I cut the total environmental footprint of making my heat and power with CHP, I'll have to pay more for carbon. And they don't like that.

CARB continues to do what it's done since its inception, which is to put the biggest burden on clean air on the new plant, so you're constantly in the business when you build a new plant of having to spend more to cut your pollution down, and then compete with people who have grandfathered permits. And, you know, until we move to output-based pollution allowances that apply to everybody, we're going to continue to have that problem. So that's the bad.

How can California speed societally profitable deployment of clean energy? My feeling is the goal is not clean energy and the goal is not cheap energy, the goal is clean cheap energy. We need to do this in a way that actually cuts the cost down, and any standard less than that, we're being lazy, it's not going to work. So we as a company and me as an individual for 35 years have been focused on ways to get more value. I think the first thing is you've got to find ways to reward the utilities for supporting distributed generation and for improving their efficiency. All I need to know as a fact is that the utility efficiency in the United States has not increased by one percentage point in 50 years. During that 50 years, we had an unbelievable technological advance in everything else, and utilities are still where they were when Ike left the White House. I need say no more. We've got to figure out a way to put this stuff in that's twice as efficient.

I think that you should deeply consider programs for encouraging all utilities to interconnect up to about 20 MW into the distribution system. The reason for that is that there are benefits that can be given to the distribution system by local generation, and I'm going to talk about them in a minute. You can't get those benefits going right to the transmission, plus it costs more.

I'm going to suggest ways that we can look at targeted CHP to provide voltage support to the transmission lines, and we've got significant academic support and almost no argument that we could cut the line losses in this country down by 60 percent. To calibrate, we spent $26 billion on line losses last year in the United States, and it took about 165 million metric tons of carbon to create the energy that we lost in the lines. And the best kilowatt is the one you don't ever make.

Finally, I'm going to suggest that you could develop a program for long term contracts that would induce oversized CHP plants to provide spending reserves. I'm not talking about a PURPA machine that can feed you simple cycle power around the clock, I'm talking about a machine that runs thermally matched, at its discretion, and runs full out at the grid's discretion, to cover the wind.

So, in the very short time, let me try and touch those just at a high level. Carnegie Mellon studies show that local generation connected to the distribution system can substantially lower the line losses. We've heard this morning about the problem that there's these system charges and they probably are too high, but there's no question but that there should be some system charges; the utilities shouldn't have to subsidize the non-utility player. But let's ask the other question: why should the non-utility player have to subsidize the utility or the public? And yet that's exactly what we do. Let's go to the math. If you're just connected to the grid, well, if you're just off the grid, you're going to produce 6.5 to 7.5 percent line losses because you don't have line losses when you're going right to the load. If you're connected to the grid, that means that you're also going to lower the power flowing through the lines to everybody else, and you get a tiny line loss savings on all of that, but you multiply it by all the power. And so in the range of zero to 20 percent of load from distributed generation, you about double the line loss savings. A good operating number is 14 percent.

What this means is that every megawatt hour of local generation running over the course of the year will on average avoid 1.14 megawatt hours of central generation. And yet we look at a heat rate that assumes that the megawatt that was made a long ways away and had to ship is exactly the same heat rate as the megawatt that was made locally -- not true.

It gets better. The problem with the electric system is what it does. When you make electricity, it goes one of four places, and only one of them is good. The one that is good is it gets to the user. The one that's definitely bad is its line losses. The one that is a mixed bag, the two that are mixed bag, is that it will make a magnetic field and it'll make an electric field. If that was the end of the story, we probably wouldn't have a universal electric system because we'd be losing everything in all this loss, but the good news is the magnetic and the electric field cancel each other out, and you get all that power back out *if* they're balanced. They're never balanced, except by coincidence because loads change, it goes up and down, and so forth, number one. Number two, you cannot ship the balancing bars down the wire. You can go back up the wire, but you can't go down the wire, it's physics.

What Dr. Ehrlich at Carnegie Mellon has found and then proven on an island in Europe is that, by hooking up a megawatt of distributed generation and giving the Grid Manager the right to control the power factor -- and I'm talking about controlling it Internet real time -- I need a little more leading or lagging power fact, but depending upon where it was placed you could on average eliminate 1.25 to 1.45 MW hours of central generation for every MW hour that you do locally. There is a little cost locally because you're making megavars, so you don’t make quite as many megawatt hours, but the numbers are fantastic, it is worth way more than the megavars that the big plants sell to each other because it's at the back end of the line, you can balance.

That's the average. Now it gets really good when you think about system benefits. During the peak, that megawatt hour with var support that's run by the grid, can avoid 2 to 2.5 megawatts of central generation. You don't have very many hours of peak, so the actual avoidance of the generation is not the big piece of economics. The big piece of economics is that we design our systems against the peak -- that's what we build the wires for, all that investment, that's what we build the peaking generation for, all that investment. So every time we put in a megawatt hour, a megawatt capacity now, of distributed generation, and have it hooked up to give power factor support, we can cut the need for investment in the system down by two megawatts to 2.25 megawatts, and that's a lot of money to flow through the system before it's done.

Let's go back to self-interest. Is that of interest to the utilities? I can't think why. They get paid a return on invested capital, you've just cut down the need for capital. The paradigm is broken. You're not going to get there without changing the paradigm.

Okay, let's go to the next thing. We have in California a big market and a lot of power comes into California, a lot of the cleanest power comes from the northwest, but we have a problem with wires. Now, I don't know if the wires will be built, I'm too old, I don't think I'll ever live to see the wires built, some of you young folks might see it, but it's a long time away. We have had a situation in the last two years where BPA is dumping power and saying, "I can't take the wind." "Shut your windmill off, I can't get it in." We've had clearing prices in certain times of a minus $20.00, BPA paying people $20.00 to take a megawatt hour because they can't shift it. Well, what are we going to do? We've got power, we need the power, and we don't have enough wires. Have the CAISO look at the node and go along and say, "I'm going to put these things in periodically on the transmission lines, I'm going to provide voltage support, the lines are not thermally loaded, they're almost all the time loaded against voltage drop when the voltage gets down so low you can't go any lower, and so it would be like giving those lines steroids.

Finally, I think that what you've got to do to do this is to have regulations that will induce line loss savings. They've got to be reflected in CHP payments and credits. Right now, the line loss savings go 100 percent to the public, and that's why there aren't any. You get what you pay for. The next worst thing you could do is give it all to the CHP developer because the utility would fight it all the way, they're not getting anything out of it. The best thing, give some to the CHP plant, give some to the utility, give some to the public, let's come to the dance and ask Senator Shaheen's question that she's been asking us at the national level, "What can we do to make CHP attractive to all the players?" Let's get out of the war, figure out how to make it attractive. Incentivize the utilities to connect DG at their level, CAISO will offer some long term contracts and get this stuff done.

The last piece that I want to bring up is that we're increasingly needing spending reserves and it's a problem that's on everybody's mind. This is a picture of the hourly wind output over a month of August in Ontario, that's a pretty big territory, and you can see that it's all over the map. You just can't count on the wind being there at any particular time and, so, it's more variable and we're losing baseload. Each megawatt of renewables rewires more megawatts of reserve. Well, what do you do? Of course, first of all, you use the hydro and stored water and so forth, but when you run out of that, you have to do something else, so the conventional answer is, after you've used the hydro, you put simple cycle gas turbines and cause them to run at about a 40 percent load and a 13.5 thousand Btu heat rate. They run maybe 3,000 to 4,000 hours; if they don't now, they will tomorrow because, as there's more wind, you need more spending reserve and it's really a problem. It adds 6,000 to 7,000 Btus of cost and emissions as a penalty to the wind. Let's think about doing that a different way. You build an oversized CHP plant. I want to talk about a cheese plant two hour drive from here. A 20 megawatt turbine would be perfectly matched with their load, their thermal load, and they need about 15 megawatts, so you'd be exporting five or trying to make it work, and that will take you four years to work that out, you heard the story this morning about the export. Instead of that, put a 50 megawatt turbine in. When you run it at 15 megawatts part load, it's so inefficient that you'll get all the heat you need because you're getting more heat out of 15 megawatts of a big turbine at part load than you are out of a small one at full load. So you've kind of got a match between the electric load and the other, and you as the owner have the right to run that thing up to thermal match, and no greater. The grid has the right to ask you to run to 50. Whenever they do ask you to run to 50, they've got to pay the incremental cost of you doing that, which are the same as if you ramped up the turbine. The net value of all that saves Btus both ways, encourages 4,500 Btu thermally matched CHP. In order to get there, and I just go on to the benefits and come back to that, we've looked at 120 megawatt wind farm. A part load electric plant only burning an incremental 4.3 million Btus of fuel a year to back up that wind field, using that identical turbine or a series of smaller turbines in CHP mode, part load, saves 7.7 million, that's a $12 million a year swing to society, that racks up to a $34.00 a megawatt cost to society. You don't see the whole $34.00 because you don't have the comparison of it being not there, but that's the benefit that's there, that allows us to sort of cut through and say, "Jeez, let's share these benefits." And I say, unless some of it is used to incentivize the developers, why would we put in 50 megawatts of capacity on the hope that somebody might buy? We need a long term contract.

If I go back for just a minute to the regulatory changes, the ISO has got offer long term contracts for spending reserve to get this, you don't need to on the gas turbines, the simple cycles are sitting out there for peaking, you just run them more often, it's -- that's the kind of policy it is. You need to modify the feed in tariff rules so that the 20 megawatt limit applies to the thermally matched part that you're allowed to run and you don't get this thing canceled out because you also provided something to provide the spending reserves. And you're certainly going to have to incentivize the utilities. Why should they do this? If it doesn't make them anymore money, all we're going to get is foot dragging.

My conclusion, California is already a leader in CHP, you've moved strongly to the transition to a 21st Century electric system, but it's a war, everybody drags their feet, got nice words to put around it, but the fact of the matter is, every CEO of the utility says, "I've got five years? Let me put this off as long as I can, leave a note in the drawer when I leave, I did my job, you put it off as long as you can." It's good for everybody but our children and our grandchildren.

I think the new programs that you're doing is going to attract some smaller scale developers and that's a good thing. I don't know how you split these responsibilities between the agencies, but we have to shift the paradigm. We've got to begin rewarding utilities to do this. I can't train my dog with the stick, I've got to give him a kibble when he shakes hands and then I've got a good dog and he's smart and I love him, and the utilities are smart and I love them, but they've got the wrong incentives.

The CARB rules, I'm sorry to say, are a disaster. Just give everybody the average CO_2 output per unit of output and let the market figure it out. You record your output, there's so much CO_2 you had to have, oh, by the way, next year you get less; and then all this stuff goes away.

We need to encourage the CHP spending reserve plants with long term contracts. We need to encourage the support along the lines because it's a way to build transmission lines without 20 years of intervention.

And finally, I would suggest that if this looks daunting, consider the experience in Denmark. In the mid-'80s, their system was all central stations, a few big red dots; 20 years later, they got a system that's something like 54 percent delivered efficiency vs. our 33 -- this is a trading partner, we can do this, it's something that we -- it's too important not to do it and be caught in another 30-year war fighting over who gets paid. My slide is blocked. Well, the last slide said thank you, so thank you.

CHAIRMAN WEISENMILLER: Thanks, Tom. A couple questions. First, you mentioned some Carnegie Mellon Studies on benefits of DG. Could you at least point us to those studies so we can get those in our record?

MR. CASTEN: I will, indeed.

CHAIRMAN WEISENMILLER: And the other one is you mention Denmark. My impression is that one of the regulatory changes in Denmark that really led to the differences between 1980 and now was basically utilities stepping in to at least develop some other projects themselves?

MR. CASTEN: That was the effect, Mr. Chairman, but my understanding of how it works is the following. In -- right after the second OPEC crisis, Denmark almost went bankrupt. They had 78-80 percent of their total energy input in the form of oil, and that price of oil suddenly went up four times and the country was in a bit of a hole. They put a huge tax on all fuel and then they said if your plant exceeds this efficiency level, you don't have to pay the tax. And the only way you could get to that efficiency level was to recover the heat that you'd been throwing away and do something with it. So they did a lot of things, but they did not sort of say "the utilities can't do this." Now, their utility structure is a little different, it's almost all municipals, they don't have the big investor-owned IOUs as much. But, yes, they did allow the utilities to come in and do it, and they closed down some big plants, they took heat out of the big plants, they developed District heating, and you can see what happened. The irony is that they actually got so far that when the North Sea Gas came in and we got the lines coming down from Norway, they actually had too much power for the lines because they're getting hydro, which is even greener, but Denmark is a little worried about sea level rise from Climate Change for some reason I don't understand because there are a lot of places in Denmark that are at least five meters above the sea level.

MR. RECHTSCHAFFEN: Tom, are there any ISOs that have adopted the kind of tariffs you're talking about?

MR. CASTEN: We have seen a maximum of a one-year contract for spending reserve, and most places, they don't even talk to you. The PJM, I think, designates who is going to provide spending reserves a month at a time. The argument is made that all we need is a price signal and that everybody will satisfy it, and if you're just bidding between existing capacity, that's probably true, but it doesn't induce new capacity. My second ISO experience, which is also negative to your question, sir, is that the New York ISO has a market for vars and they believe their market satisfies everything, and it's a very -- you know, if you're a big plant, you can make a few million dollars by selling VARS, but they won't flow downhill and they don't recognize that it's worth a different value. It's like saying, I'm in Chicago in July and I want an ice-cream cone, and I can buy it for one-third of the money in Juarez, but it won't help me a lot because I can't use it in Chicago. And they just have not recognized that those VARS have a different level of importance, depending on where they come from, and so by and large this hasn't been done.

CHAIRMAN WEISENMILLER: One other question is, you had mentioned potential of, I think, 15,000 for CHP designed around waste heat?

MR. CASTEN: Fifteen hundred.

CHAIRMAN WEISENMILLER: Fifteen hundred, okay.

MR. CASTEN: We've identified 500 MW that could be done with back pressure steam turbines, where the host is presently dropping the steam pressure down and just throwing the work away from it. Based on our studies at other places, we think there's at least another thousand where you're taking waste heat from a process, or off gas. I mean, I drove by Valero on the way up here and there's all those flares -- it's nice to look at it at night, it's real pretty, but that's all energy that could be converted into, you know, recycled into waste energy. So I think, altogether, I might add 1,500 MW to the numbers that our friends at ICF put up by including waste energy.

CHAIRMAN WEISENMILLER: And the basic -- the three most important policy measures we'd have to take to get to waste heat?

MR. CASTEN: I actually think the SGIP is going to cause the back pressure turbines just like it is, it's a sweet spot and that's going to happen, then you don't have to get an interconnect. To get to the rest of it, we're going to have to sort these things out that don't take you four years to get an interconnect and drag your feet, so forth.

CHAIRMAN WEISENMILLER: Thanks. Questions?

MR. NEFF: Thank you, Tom. The next presenter we have is John Ballam who is going to be presenting via WebEx. So I direct you to the slides as opposed to a presenter. John, can you hear us?

MR. BALLAM: Yes, I can. Can you hear me?

MR. NEFF: Yes, we can.

MR. BALLAM: Great, great.

MR. NEFF: I would say speak up if you can, it's a little quiet on that side.

MR. BALLAM: How's this?

MR. NEFF: That's great.

MR. BALLAM: I'll turn off the mic here. Is that better?

MR. NEFF: That works. Thank you.

MR. BALLAM: Well, it's nice to be with you, it's been very listening to the comments and -- just to give you a feeling of comfort, you know, because you might be worried that I'm speaking from the other coast, I was born in Berkeley. So with that introduction, I'd like to say a few works about what we're doing here in Massachusetts, alternate energy standard --

MS. KOROSEC: John, you're cutting in and out.

MR. BALLAM: Oh, sorry. I don't know if it's the phone or what. How is this?

MS. KOROSEC: That's good.

MR. BALLAM: Well, if it continues to cut in and out, let me know and I'll -- I don't know what I can do about it, but I'm on a land line. Does that still -- is that still doing it?

MR. NEFF: It sounds good, I would say continue and we'll stop if it gets bad.

MR. BALLAM: Give me a red flag if it's a problem.

MR. NEFF: All right.

MR. BALLAM: So let's see, for some reason my slide is not -- oh, there we go. Okay, so in Massachusetts, a general overview here, we have two incentive programs -- well, first of all, at this time we have two incentive programs that have resulted in 50 megawatts additional operating CHP projects since their inception. Both of them began in 2009. One of them is a utility administered efficiency plan which is part of the overall efficiency plan which is funded by on bill by ratepayers. It's a front end benefit, i.e., capital, it's at $750.00 per kilowatt hour -- I'm sorry, not kilowatt hour -- kilowatt capacity, and for under 150 KW with a maximum incentive of $112,000. And above 150 KW, it's at the discretion of the utility program administrators. All the mid-size projects, the caps usually (inaudible) larger systems -- is it still cutting out?

MR. NEFF: Yes, it is.

MR. BALLAM: Oh, gee. I don't know what I can do about that. Also, it doesn't -- my slide --

MR. NEFF: You don't have to indicate, I can find the slides here, so just send the next slide.

MR. BALLAM: Okay, thanks. So for the large systems, the cap is sliding and is basically measured against remaining funds and the need to distribute them. Eligibility, the as designed system efficiency has got to be greater than 60 percent, and it's got to pass a cost-effectiveness screening threshold established by our DPU, resulting in a benefit to cost ratio of greater than 1. And here, the benefits are basically system benefits, avoided energy and system costs, and also some non-energy benefits. Next slide, please.

There's a link there to a document that will give you a lot more information about that. The State has got two Portfolio Standards in place at this time, a Renewable Portfolio Standard which covers solar and wind, and renewable fuels, and an Alternate Energy Portfolio Standard which specifically includes CHP, which is what I will focus on today.

In general, the benefit here is that it provides -- or its intent is to provide a program structure for scheduled growth of both capacity and related incentives levels needed to ensure CHPs, that we meet the goals that are set by high level legislation such as the Green Communities Act, and the Global Warning Solutions Act, which I think are somewhat analogous to your AB 32, and in a way that is predictable. The APS is a production (inaudible) administered by the Massachusetts Department of Energy Resources (inaudible), which are called Alternate Energy Credits, or AECs, is earned per megawatt hour of net source fuel energy saved by CHP unit, and I'll cover how that's determined in another slide, at a greater than 200 KW, are required to have (inaudible) grade KWH Btu and fuel meters, and the meters are read by independent parties. All of the projects that have received a utility incentive are also enrolled in the APS, so the programs are fairly complementary.

Going further into detail, (inaudible) S, it creates an obligation (inaudible) probably your Renewable Energy Standards and (inaudible) all the retail electricity suppliers are load serving entities (inaudible) equal to a set minimum standard of the load served, percentage. And purchase of the AECs from the qualified generators buys an additional revenue stream (inaudible) and the purpose is to incentivize and recognize net GHG reduction and fuel savings, also some of the other benefits that Tom was -- system benefits that Tom was mentioning before.

Regulated Suppliers, the IOUs, can recover the cost of the obligation (inaudible) rate cases. The competitive suppliers don't have this cost recovery path. Next slide, please.

The APS was established under legislation called the Green Communities Act in 2008. (Inaudible) began in 2009 (inaudible) qualified units produced AECs. Also, the APS also includes other technologies, but these have not -

- CHP is (inaudible) look to produce almost all of the credits to be generated in this program. (inaudible) basically it is incentivizing net source fuel savings, as all of you are, I'm sure, very familiar, you (inaudible) efficiency (inaudible) CHP at (inaudible) fuel by a unit of energy (inaudible) takes for a local boiler to supply -- to meet the load, that's a certain amount of fuel. If you look at fuel at a CHP unit, it requires to meet the same loads, electrical and thermal load. It takes less fuel and so there's a net fuel savings associated (inaudible). A formula that we use is that (inaudible), so in the ISO New England area, it just turns out (inaudible) average heat rate and the line losses, it comes out to almost exactly .33. Megawatt hours of electricity metered (inaudible) Btu meter divided by .8, sort of the average for a conventional thermal conversion unit, minus the fuel that the CHP put in, and that's how many AECs you get per megawatt of fuel savings, megawatt hours.

Governing Regulations -- you can download those and take a look at them. (inaudible) cutoff dates -- new systems, only those that started up after January 1st, 2008 (inaudible) didn't want to incentivize older (inaudible) there's a provision for incremental load or modifications. Payment mechanism, certificates are traded, so meter readings are taken, they're submitted to the NEPOOL GIS, they (inaudible) certificates, the certificates are traded, and usually the settlement -- the minting and the settlement are one-quarter apart. Next slide.

Obligation Schedule (inaudible) 2014, but we are trying to meet half a percent increase per year of the load.

Some results, economic benefits. Our systems (inaudible) is 50 to 1 megawatt projects. For these systems, the APS alone is not sufficient to ensure the financial viability. However, the utility benefit when combined with the APS is usually -- will actually result in a pretty significant improvement in both payback and the ROI and is often enough to push the project over the threshold.

Projects greater than a megawatt, APS is the more significant factor due to the cap limitations on the utility administered incentives. Source Fuel Savings -- so from 2009 until September 2011, we generated about 600,000 AECs. (Inaudible) environmental benefits -- next slide, please. Next source GHG reduction, of course, they'll be specific to the emission coefficient of the regional grid system. For Massachusetts, the average grid emission factor right now is about 828 pounds per megawatt hour. And for our grid in natural gas fueled CHP system (inaudible) about an 18 percent net reduction, about .078 short tons per AEC. (Inaudible) a net reduction of approximately 46,000 short (inaudible). Next slide.

So impact to stimulation of CHP (inaudible) Massachusetts. Total CHP capacity here is (inaudible) SCIA is about a gigawatt (inaudible), about a gigawatt of that are central plants, central power stations, all pre-2008. And of that, almost all of them are greater than 230 megawatts. And I should say on the side, one of those, I'm not sure, is still a cogenerator, but at least it's listed as one. (Inaudible) APS installed capacity of 50 megawatts is only six percent of the total installed. (inaudible) APS represents, but (inaudible) percent of all CHP installations post-2008. So what happened here is that these large CHP projects basically dropped off the face of the earth (inaudible) or well (inaudible). All of the post-2008 plants have been smaller than 25 megawatts with a large majority under 500 KW. Of those, of these new post-2008, the APS has been a major factor in successful progress to completion for those projects.

(Inaudible) they're concerned, obviously, we would like to see -- we would like to see a faster (inaudible) of CHP here in Massachusetts and some of the factors which have (inaudible) listed some of them here, and this is by no means a complete list. One of the major ones is lack of access to capital due to the economic conditions since 2008. Another one is the complex information requirements to qualify for the utility administered benefit. That really flows out of the fact that the benefits are predicated on avoided cost, a lot of which are heavily weighted towards being able to ensure that these systems are going to be running during peak summertime, which here in Massachusetts often coincides with a lack of a thermal load, so there the utilities like to see almost hour by hour thermal data, historical data, which is not always easy to come by. The existence of conservative stand-by tariffs in one of the major utility service areas -- this possibly will be being relaxed due to a settlement that was reached yesterday. So really, this next bullet doesn't belong here, so let's forget it, my fault. Lack of a Federal Investment Tax Credit large enough to spur limited partnership invested by third parties. When we compare growth of CHP and the mechanisms for financing it with our PV solar program here, the difference between the 10 percent and the 30 percent is a large factor in being able to round up investors.

Given all of that, the APS has been a major factor in successful progress to completion. A couple of other factors are limited effective coordination between the two State programs, and I caution you folks there in California to pay attention to the difficulties sometimes of tying programs together so that they actually operate in concert as they were supposed to. And, again, the slow acceptance of CHP benefits by the utility programs, they are still rather hesitant to accept the fact that CHP can be counted on when it's needed. Next slide. I lost my slides here, so hold on a second, sorry. There we go.

Some possible relevance to what you folks are up to in California. So the two Massachusetts programs, and particularly APS, have been recognized by the people in the sector, the participants, as successful insomuch as they have been -- the projects that have been completed would not have been completed for the most part without them. But the other factor I mentioned, the other inhibiting factors can combine to, you know, overcome the push and the progress that could be, oh, very important once this legislation is passed, whatever it might be, if it's (inaudible) Portfolio Standard, that one doesn't back away with it and think, "Well, there, I solved the problem, I've got a (inaudible), I've got a schedule, I've got an incentive, and everything should just proceed (inaudible).

(Inaudible) a look just for your information of how our projects are distributed by end use (inaudible) of them are either industrial or (inaudible). A couple of our large campuses have gone ahead and put in gas turbines, have a couple of rather, you know, a few (inaudible). However, in terms of pure numbers, the (inaudible) 5 megawatts has a lot more projects. (Inaudible) some by system type, (inaudible) interest, I won't cover that, final page is some of our contact information here in Massachusetts and we would be very glad to (inaudible). And I did put in an appendix here with more details, more program-related details on an administration quality assurance and things of that nature, which might be of interest to you if you are considering this type of a program. That concludes my presentation.

CHAIRMAN WEISENMILLER: Thank you very much. This is Chair Weisenmiller. A couple questions, the first one was you mentioned that there were some other technologies that were eligible under the APS, but have just not happened. What were those technologies?

MR. BALLAM: The major one were flywheel storage and it turns out, for whatever reason, we've only had four megawatts of flywheel storage installed under this program, were applying, improved and installed, and actually that particular company that was doing that has since gone under. There was another rather ill-defined technology called Advanced Steam Technologies and, to be frank, I don't think anybody quite knows what that means.

CHAIRMAN WEISENMILLER: Okay, was that limited to flywheel storage, or storage in general?

MR. BALLAM: Flywheel storage, in particular.

CHAIRMAN WEISENMILLER: Okay. And just the other question which you may not know, I was just trying to understand what the value of RECs are now on NEPOOL?

MR. BALLAM: The value of RECs right now are -- Class 1 RECs are almost at $50.00.

CHAIRMAN WEISENMILLER: Okay, thanks.

MR. BALLAM: Yeah. Oh, I should mention, I didn't mentioned, but I should mention that our program allows a combined heat and power system that is (inaudible) both the AECs and the RECs, which right now would amount to about 8 cents per kilowatt hour.

CHAIRMAN WEISENMILLER: Great, thanks again. Any other questions? Sure.

MR. BIERING: Brian Biering with Ellison, Schneider and Harris. I'm here on behalf of Aceco Generation and Rio Bravo. I have more of a general comment about the --

CHAIRMAN WEISENMILLER: Why don't you hold the general comment for the end?

MR. BIERING: Okay.

CHAIRMAN WEISENMILLER: These are specific comments for the person on the phone.

MR. BIERING: Thank you.

CHAIRMAN WEISENMILLER: Okay, thanks again. Let's go on to the next speaker.

MR. NEFF: Thank you, John. I have to apologize to the people in the room, WebEx was recording it, it had something to do with the speakers within the room, and so if you want to hear his full explanations uninhibited, I encourage you to go online once we have the recording posted.

And with that, I'll be turning it over to Rizaldo Aldas who is going to cover the next section.

MR. ALDAS: Thank you, Brian. Good afternoon, everyone. My name is Rizaldo Aldas, I am with the Energy Research and Development Division of the California Energy Commission.

This session is on the technology innovation in overcoming CHP barriers and what I will do here is just provide you a hopefully quick overview of the CHP RD&D, and then I will call two gentlemen who will be providing -- talking about specific projects that are funded under the program, the Public Interest Energy Research Program.

First, let me start with the policy drivers. All research programs under PIER are driven by policies and these are just some of the policy drivers for CHP RD&D, and most of these, I think, have been mentioned in earlier talks. SB 1250 here provides specific investment categories for PIER funding. And among these is the Advanced electricity generation technologies that exceed applicable standards to increase reductions in greenhouse gas emissions from electricity generation, and that benefit electric utility customers.

The Scoping Plan under AB 32, as well as the Governor's Clean Energy Jobs Plan calls for a specific additional CHP capacity at a certain time. Now, those policies help us describe the overall goals for the program, and that is to advance the science and technology, reduce barriers and increase market penetration of CHP/CCHP, and to help achieve that goal we adopted some strategies such as expanding the CHP/CCHP, recognizing that CHP is the most efficient form of DG. We work on developing innovative energy supplies focusing on desirable qualities, including reducing polluting emissions, increasing energy efficiencies. We're looking at developing hybrid generation, fuel-flexible systems, as well as demonstrating diversified applications of CHP that use renewable resources.

In this slide, I tried to provide you an overview of the portfolio of CHP technologies funded by

PIER, by technology types. You can see here the reciprocating engines, category first dealing with reciprocating engine, including modifications, reengineering, that represents 27 percent of the funds. The work on the turbines are mostly on a microturbine such as fuel- flexible or biogas fuel microturbines, (inaudible) 36 percent funding the fuel cells. We have worked on high temperature fuel cells, renewable fuel cell.

And then the CHP renewable technology, I tried to lump all the other works not related with -- not directly related to fuel cells, or gas turbines, or engines into this category, and this includes work like emission control technology, those activities that are looking at integrating a CHP, novel controls for operating CHP, as well as the market analysis and databases included performance standard activities under this area. And that represents 20 percent.

And these projects have a common emphasis or goals such as reducing cost, demonstrating the system in California high efficiency, low emissions, and the reliability, availability, maintainability, and observability including following performance testing protocols.

Now in the next three slides, I'll try to give you examples of some of the projects that we supported. You have heard about this project on a 100 KW engine BBEST power system, the one on the upper left side of the slide. The one on the lower left-hand side is on the emissions control technology. The next speaker will be talking more about this one.

The figure on the upper right-hand side of the slide represents the research on ongoing project that is looking at retrofitting microturbine to commercial scale fighter boilers in CHP applications, while the figure at the bottom right, represents our project where the contractor is developing and demonstrating microturbine-based CHP system for turbine oxidizers that are using industrial process to address VOC emissions. Now, this is another example of ongoing project with GTI and the aim for this is to develop cost-effective gas turbine-based CHP system that improves the overall efficiency, while meeting or exceeding the ARB 2007 Emissions Standards for distributed generation. This is targeted for a small to medium-size industrial boiler and one of the key innovations here is the use of natural gas-fired supplemental burner to allow low emissions without the use of expensive catalytic exhaust gas treatment. Right now, the project has completed at this time, it is conducting refinement of the system, as well as preparing for fuel demonstration.

Now this other example is also an ongoing project, expected to be completed by the end of the month and this is an example of a CHP system running on renewable resource, specifically biogas. This is a project with Gills Onion Company located in Oxnard, California and being conducted with GTI. This project has successfully demonstrated conversion of the waste product or waste water from the processing of onion to generate biogas and then clean up that biogas and use that clean biogas to run a 200 to 300 KW molten carbonate fuel cells. One of the key innovations here is the cleanup and conditioning system for the biogas. The project is successful, it is serving as a model for the food processing industry in California, and the project is also receiving a number of awards. The benefits in terms of reduction in natural gas, as well as greenhouse gas emissions is also provided here.

Now, in this slide, I tried to summarize our major initiatives in two categories, one is on the combined heat and power and distributed energy resource technologies. These initiatives consist of several ongoing projects at different stages, some are nearing completion, some have developed designs, and some are doing field tests. And the goal for this initiative is to demonstrate and develop innovative, efficient and cost-effective CHP technologies, develop low emissions technology, and then use alternative fuels such as biogas, flared gas and natural gas.

The other initiative here is the hybrid generation fuel flexible DG/CHP/CCHP where we are looking at integrating emerging multiple technologies and fuel flexibility. This is an ongoing solicitation, we released this on January 6th, and we expect to receive proposals by the end of this month. If you want more details on that, you can look at the details in the CEC website.

Now, looking forward, we anticipate that R&D on CHP will continue, further refine, and deploy the technology. There are some potential areas that we may be focused on such as accelerating the deployment of CHP in industrial, commercial, institutional and other new areas including food processing, manufacturing and retail.

We are also looking at the application of CHP for biogas and local renewable resources to reduce consumption of natural gas for heating and power systems, capturing the waste heat from various industrial processors. The application of CHP for associated gas such as those produced from oil and gas fields in LA Basin and other low-Btu gasses. And then, of course, continuing the innovations to further refine and improve such as looking at improving the integration of systems with building and industrial processes, develop and demonstrate Smart Grid readiness, address renewable intermittency, and improve efficiency of reducing emissions.

Now, I will not go through these questions, I just want to point out that we have some questions that we included in the agenda. We will appreciate receiving comments from the public and that will help us move forward. And with that, I would like to call on the next speaker, Mr. Keith Davidson, President of DE Solutions, who will be talking about the project on Ultra Low Emission Control for Rich Burn Engines. Keith.

MR. DAVIDSON: Thank you, Rizaldo. DE Solutions is a small San Diego-based consulting firm and, among other things, we get involved with advanced technology development mostly with people involved in the combined heat and power industry. And I've had the fortune of participating in a number of projects that were sponsored in part by the California Energy Commission, and two of them I'm going to talk about today are ones that were directed at significantly improving the emissions profiles on rich burn engines. And rich burn engines generally are less than or equal to about one megawatt in size. Rich burn engines are those where you operate at Stoichiometry exact oxygen, or exact amount of air and fuel, slightly rich, actually. And then the larger size engines, over a megawatt, are typically what they call lean burn engines, which they put excess air in for some other advantages. But all engine technology has been extremely challenged by direction in air quality emissions in California. CARB probably started it back in the early 2000's when they adopted requirements for non-permitted prime movers to equal central station plant emission levels. And for permitted prime movers, which for the most part are engines and larger gas turbines, they issued guidelines to the local air districts because that was outside of their prerogative to force that. And so far, the South Coast Air Quality Management District about two years ago was the first one that implemented parts of the CARB '07 Guidelines to engine technologies. And they actually adopted the NO_x standard, not quite adopted the CL Standard, and I'll show you that a little bit later. But furthermore, there's a statewide requirement that, in order to get SGIP, in order to participate in AB 1613, you've got to meet the NO_x requirement for CARB '07. And it's turning out that these levels are extremely low and very very difficult for reciprocating engines to achieve, so this was kind of the thrust of two R&D projects were to not only get down to those levels, but sustain performance at those levels without frequent testing, which really means you have to be able to exceed the requirements.

And the two projects, real quickly, one was with my company, DE Solutions as the prime, with co-funding from SoCal Gas Company, and with Tecogen, who you heard from earlier this morning as being the primary subcontractor and manufacturer. The second project, the prime contractor was Southern California Gas Company, it was with a San Diego-based company that makes air fuel ratio controllers for engines and gas turbines, and I was part of that team. And, you know, the objectives I stated, to exceed requirements and to sustain performance without frequent operator intervention.

This just gives you a quick sense as to what -- how difficult things have become. The BACT limit, which still exists for most of the state, is -- and the conventional metric, and the ones the Air District uses, are parts per million corrected at 15 percent oxygen. And it's 11 ppm for NOx typically and 70 ppm for CO. The CARB and South Coast, both have gone to an output-based standard, so it's per megawatt hour, and it does give you some credit to the extent you use heat, which is a good thing. But you can see when I translate the pounds per megawatt hour goals to parts per million, you can see how challenging it's gotten, it's maybe about a four-fold reduction in NO_x, but the CARB levels anywhere, of course, with a 10-fold reduction from the current BACT levels, which are really the biggest challenge.

If I can just take a second to -- this kind of frames the problem. In a rich burn engine with the three-way catalyst, like are in most automobiles, to the extent you have air in the exhaust, the catalyst is not going to be able to reduce the NO_x. So on the left, you can see the NO_x is real high, as you richen out the engine, add more fuel, the NO_x comes down to very low levels. But at the same time, you've got a competing factor with carbon monoxide where, as you add a little bit more fuel and richen it out, it tends to shoot up and at that bottom line there, kind of triangle, you see sort of this really tiny point at what the CARB '07 rule, where the reciprocating engine has to perform at to stay in compliance. And that is a big part of the challenge.

Okay, so the two technology approaches, both teams of contractors pursued a number of different solutions and two really emerged, 1) Continental Controls, they've got a very precise air fuel ratio controller and so they build off of their core technology and included a number of other system improvements, including the use of NO_x sensors, which is the first time ever really a NO_x sensor was used on a rich burn engine for feedback, you know, post-emissions, post-catalyst feedback. They put in a much more robust catalyst and used a technique called dithering, which is used a lot in the automotive industry.

Tecogen took a little bit different tact, they came up with an innovative catalyst configuration that widened the compliance window, that little tiny window that we showed you, they actually came up with an approach to just make it a lot easier to hit. And lastly, the approaches aren't mutually exclusive, so you can potentially combine them. This is the Continental Controls concept -- in the interest of time, I know we're kind of stressed here, I'm not going to go through it all, but it's pretty much what I said a minute ago -- off to the left are pictures of their electronic gas carburetors, their controller and software is at the top right, and the NO_x sensor is pictured at bottom right.

This is a schematic of the Continental Controls System and you can see that the NO_x sensor is at the outlet of the exhaust and here it's called a Lambda sensor, but it's really an oxygen sensor, same one that is used -- similar to the one that is used in the automotive industry at the front end, and traditionally it's that Lambda sensor, oxygen sensor that controls the air fuel ratio controller. The problem is that the Lambda sensor, oxygen sensors tend to drift and so you may be getting good emissions one day, you know, the next month there has been some drifting and you're out of compliance. So the NO_x sensor actually provides feedback to keep the upstream oxygen sensor tuned at the exact appropriate level. Here is some data, you can see this red line here is the NO_x limit, the CARB CO limit is up here, nobody really requires that right now, and the South Coast CO limit is up there. You can see there's a few excursions; in the way of excuses, I guess, this is an atypical CHP application, it's a 300 KW engine that operates at loads between about 10 percent load, or less than 10 percent load, up to maybe 40 percent load, and at the very low load levels, the exhaust temperature isn't hot enough to fully activate the catalyst, so that's what accounts for some of the excursions. But it's an older system, so the permit is way off the charts, so none of these things make them in any way, shape, or form in violation of their permit, but it gave us a better understanding as to what's doable and what's not doable. And I think what we know now is that, for typical CHP applications where you operate them close to full all the time, it's going to perform very well.

The Tecogen system, switching projects, again, they're the ones that widen the air fuel ratio window, their concept is a dual stage catalyst and where they use the first stage, which is your typical three-way catalyst, to get the NOx down to very very low levels without really regard to how much CO that you're producing, there is some upper limits to it, and then with proper conditioning, and the conditioning has to do with lowering the exhaust temperature before the second stage, and adding some air. So you put air injection and, then, in the Tecogen system which Bill Martini showed, 100 KW, it's a little aquarium pump is all you need to get the air in there; and to reduce the heat in a combined heat power system, you're doing that anyway, so it really doesn't require any kind of an ancillary cooling system to be added.

So that's it in a nutshell and this may be a little bit hard to follow without me pointing to it, but this was tested by a third party down in Lake Forest by an engine R&D house, AVL, and that first -- that short horizontal arrow shows what the window of control needed to be without air injection, and the wider band just shows what it is now for the system with air injection. And this is 10 months of fuel test data at one of their sites that have been operating for several years up in San Fernando, California. That just shows -- so the new emission system was retrofitted in. This shows 10 months worth of data, and you can see how low and how well this thing performed. The South Coast CO limit's way up here, the CO's almost zero, NO_x is almost zero. So it's really turned out to be a phenomenal technology, we feel.

The Continental Controls and Tecogen are both proceeding with commercialization. Tecogen is already integrated into their larger co-gen module, they're integrating it into all of their other product lines, which include smaller co-gen systems, engine chillers, and an engine-driven heat pump.

Continental Controls is starting to pursue the retrofit market right now, a lot of people that have engines that are having trouble, mostly in the South Coast Air Quality Management District, and keeping their engines in tune on a continuous basis, and they're all looking at expanding the market with dealers and the engine OEM manufacturers and, in the case of Continental Controls and with Tecogen, I think they're also looking at making this technology available to others outside of people that just have their products.

So that, in summary, both of these technologies are a fairly low cost incremental item, yet enables the least cost CHP technology which is engines, less than five MW in size, to remain a viable option in California. It makes available technologies that enable continuous compliance with the permit limits and we think it will create a new clean environmental image for engines. Thank you.

MR. ALDAS: Thank you, Keith. The next topic will be on the Homogenous Charge Combustion Technology, or HCCT for CHP Applications. That will be Brandon from Makel Engineering.

MR. BLIZMAN: Hi, my name is Brandon Blizman with a company called Makel Engineering, a small research company in Northern California. The reason I'm here today is to kind of give you guys a little insight as to where some of your research money from PIER is going. We've been funded by PIER to do a research project in the development of Low NO_x Technology. Now, being an engineer, I really like where today I've been seeing lots of acronyms and I can tell that the CHP community likes acronyms, as well. Here's one acronym I hope you guys walk away from today's meeting with, it's called HCCI. Well, what is HCCI? It stands for Homogenous Charge Compression Ignition. It's an engine emission cycle that kind of -- it's a hybrid, if you will, of compression ignition and spark ignite concepts. What it does is allows the low energy content fuels like biogas to combust at a high efficient low emissions method.

So why would we be doing HCCI for CHP applications? Well, first of all, it's highly efficient, upwards of 80 percent efficiency -- I'm not going to go into the details of that, but it's obviously going to reduce electricity cost for CHP owners, displace the need for fossil fuels. The other benefit, obviously, is the low emissions. Without any NOx after treatment, we're able to see lower, I guess, on the low end of 3 ppm, obviously it reduces air pollutants. Fuel flexibility, HCCI has around the world been demonstrated on a variety of fuels. Makel Engineering successfully has demonstrated on landfill gas and we're looking forward to demonstrating on digester gas, low cost, the CHP system is looking at cost of around $1,200 KW to install.

Some of the technical challenges that we see for the development of this technology is biogas operation and biogas situation; the Btu content can vary almost sometimes on an hourly basis, depending on the composition. That's where Makel Engineering and our research partners in Berkeley have been able to bring our expertise to develop a control system to maintain HCCI combustion.

Heat transfer components -- some of the conventional heat transfer components, you aren't able to use those on an HCCI combustion cycle because the exhaust gas is a little bit cooler than on a typical reciprocating engine. Now, continuous operation, as with any other CHP application, you know, variable thermal and electrical loading requires some active control systems.

To control HCCI, specifically for biogas, active thermal conditioning of the air fuel charge, it's the lean combustion, you know, we're talking air fuel ratios anywhere from 50, to 60, to 1. So that intake charge gets heated, regulated, and auto ignition takes place. Now, this is the complex function of the engine geometry. Again, there's an active control system. If that intake charge gets too hot, it's going to pre-detonate, if it's not quite hot enough, it's not going to fire at all. So why would Makel Engineering be looking at this as a marketable product? Well, we really think that renewables, in general, and biogas specifically has a very significant opportunity for us to develop this technology and deploy this technology. We think there's about a 760 MW of biogas available and our potential for 160 MW of biogas from dairies available in California; unfortunately, we're talking about potentials here, we're not talking about currently installed. From a biomass standpoint, all the other biomass types of facilities -- capacities -- that totals around 180 MW. So you can see why we're trying to go after kind of the larger market focus. That's not to discount the other applications for CHP, HCCI, light industrial applications such as food processing plants, hospitals. A lot of the challenges there are because of the site infrastructure, you know, is there a high electrical load? Is there a thermal load? It kind of depends on the site-specific. You know, the systems that Makel Engineering has developed, we've kind of got three systems that we've been working with U.C. Berkeley on, and the first one is the landfill gas system. We successfully demonstrated a 30 KW system at a landfill and we were able to generate kind of to verify what the labs have been generating, kind of an efficiency NO_x profile, and I'll show that here in just a minute.

The second system we're developing, it's currently under development, is not a CHP system, it's just for straight distributor generation, this is kind of a scale-up of that technology we developed at the landfill, you know, characteristics are that it's about 35 percent efficient, it's hopefully going to be certifiable after our demonstration period, and it's got a standard grid interconnection.

The third system we are developing is a CHP system, this is kind of a -- let's just say a sweetener for the landfill gas system, we're going to try to make that system a little more efficient. We anticipate around 80 percent CHP efficiency.

Here's a little bit of details about our landfill gas system. We developed a prototype, again, working in conjunction with U.C. Berkeley researchers. We demonstrated a landfill in Butte County, California, it saw about 500 hours of landfill gas, and we were able to generate this curve you see down here on the right, it's an efficiency vs. emissions curve, and that was kind of the profile we used to move forward with this technology. This next system here, we're developing with some PIER funding. This is to scale up the technology and you see the picture there, it's kind of our concept of the system, it's going to hopefully be capable of around 100 KW. It's going to have that same emissions and efficiency profile. It's basically a stock diesel engine block with an advanced control system on it and some thermal conditioning.

Our CHP system, now, you can see kind of a system schematic there, I'm not going to get too much into the details here in the interest of time, but using a closed loop recovery system, we think we're going to see efficiencies in the 80 to 90 percent range.

Now, operating on simulated biogas at our testing facility indicates that we've seen some pretty significant reasons why we would want to advance this technology, 80 percent efficiency. Now, we're working in conjunction with SMUD. This is one of the things that we learned in our previous project, is in developing these kind of projects to get your interconnect dealt with, you want to bring some of your utility partners on your team. It happens to maybe streamline the process. Our first demonstration site for this 100 KW system is going to be at the Tollenaar Holsteins Dairy in the next few months here. They currently have a system, a digester installed, and they're producing about 150 KW. The CHP application there is for thermal management of the digester and hot water for the wash down.

Our other CHP system, the smaller system, is going to be installed early next year in Galt, California at the Cal-Denier Dairy. Their application for CHP is to have hot water at onsite laundry facilities.

I'd like to kind of wrap things up there and I'm open to any questions, and here is my contact info for the future.

CHAIRMAN WEISENMILLER: Thanks very much to all the panel for the presentation. Any questions from the audience? Again, thanks for organizing this, this is pretty interesting.

MR. ALDAS: Thank you very much. If there are no questions, I will be calling on David Vidaver for the next panel.

MR. VIDAVER: Good afternoon, Chairman, ladies and gentlemen. I'll get on the right slide here. My name is David Vidaver. I work for the Energy Commission's

Electricity Analysis Office. I work primarily on long term planning issues and I probably know less about CHP than anybody in this room, so this is going to be a very brief presentation of about six slides, and then we can get to people who can provide you with some valuable information.

The loading order includes Combined Heat and Power. We see the two targets that are bandied about quite frequently, 6,500 megawatts by 2030, and the Governor's Clean Energy Jobs Plan, and the 4,000 megawatts/6.7 million metric tons by 2020 in the AB 32 Scoping Plan issued by the ARB, and updates to that plan no longer mention a megawatt target, the target specified in terms of GHG emissions reductions, but the 6.7 million metric tons has made its way into other forums.

The ARB targets, both megawatts and GHG reductions, found their way into the CPUC's 2010 Long Term Procurement Proceeding. The standardized planning assumptions used in that proceeding included the continued operation of existing CHP plus the IOU share of 50 percent of the ARB megawatt target, with outputs split 50-50 between onsite generation and export, in keeping with ARB's Scoping Plan assumptions.

The megawatt numbers that are presented in this slide are actually net energy for load, not assumed CHP capacity, which is a bit smaller, as a share of CHP output would be consumed onsite, obviating the need for slightly more central station capacity due to transmission losses.

A review of public utility filings in the 2011 IEPR and Integrated Resource Plans that they have made available indicate that public utilities as a rule do not explicitly plan to meet future needs with new CHP. I will not offer an explanation for this, I assume by merely pointing these facts out we might hear from the POU community in oral or written comments. This is significant as targets and planning assumptions adopted by the CPUC for entities under their jurisdiction, based on the ARB Scoping Plan, logically assume that POUs will contribute towards meeting statewide targets, and as Mr. Darrow pointed out this morning, roughly one-quarter of the CHP potential in the Base Case he models will come from LADWP, SMUD, and "other."

The set aside of roughly 1,500 megawatts for CHP through 2020 in the 2010 Long Term Procurement Proceeding may seem somewhat innocuous, given California's current capacity surplus and the expectation that large amounts of renewable capacity can be expected to be developed during the remainder of the decade. But, as we all know, more than 12,000 megawatts of gas-fired generation is expected to be retired by 2020 in order to comply with the State

Water Resource Control Board's policy on once-through cooling. Decisions regarding the development of resources lowest on the loading order, conventional gas-fired generation, will likely be made as part of the CPU's 2012 Long Term Procurement Proceeding, in other words, perhaps as soon as the end of this year. This is necessary due to the time needed to contract with, permit, and construct the new gas-fired generation needed for local reliability and to integrate intermittent renewable resources.

While he amount of capacity needed remains to be determined, parties generally agree that such capacity will need to be flexible, quick starting, fast ramping, and able to operate over a wide range of output. The amount of capacity authorized will depend in part on planning assumptions regarding preferred energy resources. Energy efficiency, both committed and uncommitted, demand response, renewable resources and, of course, combined heat and power.

Parties have focused and are focusing on the capacity value of renewable resources and the California ISO's stakeholder process on the integration of renewable resources into the electricity system. Assumptions regarding other preferred resources in the Long Term Procurement Planning process have perhaps received less scrutiny to date and are such that California ISO cautions prudence in planning that these resources will be available in the amounts assumed.

In sum, failure to realize CHP development in the next two to three years may result in additional gas-fired generation to meet local capacity requirements and integration needs, or delayed retirement of once-through cooled facilities.

These are the existing programs devoted to CHP, one could logically contend that, as currently constituted, they cannot be relied upon to meet a lion's share of a, for example, success in 500 MW target over the next 12 years. This isn't to say that we couldn't see a large amount of CHP developed through other mechanisms, including pure economics. The *Spark Spreads* were anticipating -- encourage new development of CHP, the obstacles to that development pointed out here today, notwithstanding.

The perhaps most significant variable which affects CHP going forward is the impact of the QF Settlement. The settlement requires the investor-owned utilities to develop 3,000 MW of new CHP contracts, but it should be noted that existing CHP contributes to this goal, and there is a companion target of 4.3 million metric tons of greenhouse gas emissions, the CPUC jurisdictional share of the ARB target. But, least cost/best fit criteria may be used by the utilities to justify failing reaching those targets, and the incremental contributions of CHP to meeting the GHG reduction target on a metric ton per megawatt basis could be somewhat small.

So the presentation by Jen Kalafut of the California Public Utilities Commission, which is going to follow me, and the panel discussion, which is going to follow that, is largely going to focus on these questions: what are the possible impacts of the QF Settlement on the development of new CHP in California? So I'll stop wasting your time and introduce Jennifer, whose office at the CPUC -- well, I'm not exactly sure what you did, but I know she knows far more about the QF Settlement than I do and has done far more analysis with access to far more data than I have. So, thank you. Any questions?

MS. KALAFUT: Okay, thank you and thanks for the intro, David. I'm not too sure what I do either, so…. And I did want to address a question that came up earlier regarding the SGIP Program. I heard from my colleagues at the PUC that all bottoming cycle is meant to be eligible for SGIP, it was not just a Rankine Cycle. I think Barbara brought that up before.

So I am going to go through some of these slides rather quickly, there are quite a few here, and I know that we're limited on time, but will say a few brief words about tracking CHP capacity and GHG emissions, talk a little bit about some of the key concepts of understanding GHG analysis of CHP, and then really get into the QF CHP Settlement and GHG accounting underneath that, and a few sort of simplified scenarios that CEC was interested in seeing.

So we heard from ICF this morning on their work on tracking CHP in the state so far, and I think that they've done a really great job on this. Estimates on existing CHP capacity in California to date can vary widely. A lot of this has to do with difficulties in estimating how much CHP is consumed onsite for some facilities, for CHP exporting to the grid; while there is public data available for Qualifying Facilities (QFs), there's no public data available on non-QFs.

As ICF also mentioned, we had a lot of lack of common data points among CHP databases, including CEC, CPUC, and the California ISO. And historically there's been a lack of a common definition of “capacity” which has made it hard to track well. But, as I said, CEC and ICF have really further narrowed this gap through a project-by-project analysis. And the good news is there's better data collection coming, both with the ARB cap and trade regulation and the CPUC reporting requirements for IOU procurement under the new QF/CHP Program.

The CPUC did do some Data Collection in 2009 and 2010, which returned around 67,000 [sic] MW of operational CHP in the IOU's territories, so this data is a couple years old at this point and it has changed a bit. I will just say that I think the conclusions are largely consistent with what the ICF has found and that most of the CHP is in QFs, and sort of the vast majority of CHP capacity is in larger projects.

So tracking GHG emissions from CHP. This can also be challenging because CHP, as we know, has a wide range in operational profiles. It can range anywhere from 100 kW to -- I think the biggest system we have in the state is 300 MW, or maybe even larger. Capacity factors can run anywhere from 10 to 95 percent. There's a lot of variance in how much power to heat a particular CHP facility will be producing, and also a lot of variance in the ratio between what is being exported and what is being consumed onsite.

Measuring efficiency in a CHP unit is also unique because you have to look at both the electrical and the thermal efficiency. And these efficiencies often have an inverse relationship. If you're generating electricity at a very low efficiency, you're producing more waste heat, which drives up the ability for waste heat to capture, and then obviously your thermal efficiency.

Finally, there's some more study that is needed to be done on what CHP is avoiding in terms of the efficiency or the emissions factor of the grid and the efficiency of standalone boilers.

So this is just a formulaic sort of explanation of what I just said. Total efficiency is a straight sort of the electrical efficiency plus thermal efficiency. The power to heat ratio, as I mentioned, looks at how much electrical output over the thermal output, and then sort of a key factor in understanding the GHG analysis of CHP is what's often referred to as a double-benchmark. And this simply means that, when comparing CHP against separate heat and power, two avoided emission factors are needed, what would CHP -- if not for the CHP facility, what would the facility be using in terms of a standalone boiler, and what is it avoiding in terms of the grid efficiency?

One way to think about this double benchmark is to look at this curve and, for those of you who haven't seen this curve before, a simple way of looking at this is for CHP operating towards the left-hand side of this graph, so with a very low power to heat ratio, and so therefore producing more thermal than power, that facility is competing against the efficiency of a standalone boiler. So the efficiency is increasingly, in order to be net GHG beneficial, it increasingly has to be more towards the 80 percent range, where a CHP facility operating more towards the right-hand side of the graph is operating more like a generator and has to compete against the efficiency of the grid.

You know, just to say quickly about some assumptions regarding CHP, the ARB Scoping Plan used a avoided grid emissions of around 437 kg of CO_2 per MWh, and this is based on a weighted average statewide emissions from gas-fired generation in 2002 to 2004; and as we sort of look towards the future, it may be worth considering what the potential avoided grid emissions would be in 2020. As we know, our grid is getting cleaner, and if we think about what the load growth in natural gas generation will be, we could envision a mix of new combined cycle gas turbines mostly, and then some new combustion turbines, which typically act as our peakers, which would produce a avoided grid emissions closer to around a 7,100 heat rate.

If we look at this, the impact that this has on sort of emission reductions from CHP is, as the grid gets cleaner, we move from that blue line up to that yellow line, and so, as we go forward in the future and as the grid potentially gets cleaner, it becomes harder and harder for CHP to compete from a GHG perspective. And I'm moving through this rather quickly, so let me know if you have any questions.

Just moving on to the QF/CHP Settlement. In November of last year, a global settlement was reached between CHP representatives and the IOUs, along with ratepayer advocacy groups, that put in place a new CHP program through 2020. There are a number of components to this settlement and I've listed here some of the key provisions, but what is most relevant to this discussion is the megawatt procurement and GHG reduction targets for IOUs, for the IOUs.

As David already mentioned, under the QF/CHP Settlement, the IOUs have a megawatt procurement target of 3,000 MW by October of 2015, it may be November 2015, but by the end of 2015. And this can be a mix of new or existing CHP. And then the IOU GHG reduction target is an incremental 4.3 MMT CO2 by 2020. And as David already said, this is based on the IOU's share of the ARB Climate Change Scoping Plan CHP target.

MW and GHG accounting towards the targets are very specific to the Settlement. This takes into account that no two CHP facilities are alike and the accounting really reflects these differences.

Some of the rules for GHG Accounting under the QF/CHP Settlement include an avoided emissions calculated using the “Double Benchmark” and the Settlement defines the Double Benchmark at an 8,300 heat rate and an Avoided Boiler Efficiency of 80 percent. The settlement does not contemplate different avoided emission factors for export CHP or for CHP that's being used onsite.

Some nuances in the accounting for the QF/CHP settlement for the GHG target is, if the IOUs have a "must take" procurement, so under the PURPA Program, for example, they have to sign up a particular CHP facility and that facility is net GHG emitting. It will not count -- this is not worded correctly, but it will not count as a debit in the GHG target. So, if the IOUs have to take on a particular type of procurement that is not GHG beneficial, it's not going to count against them in reaching their GHG goals.

Another nuance is for terminated and shut-down facilities, the energy, and therefore the GHG emissions, are replaced at a defined market heat rate. So the Settlement envisioned that, if something shut down, those megawatts can't just disappear, but they're being replaced by something, and that sort of factors into the GHG accounting, as well.

And finally, utility-owned generation can only account up to 10 percent of the IOUs’ GHG target.

In running some of the scenarios that CEC asked for, we used the data that we collected in 2009 and 2010. From that data, we did have some specific performance information for about two-thirds of the CHP IOU fleet, or about 4,500 MW. And if we wanted to just take a snapshot of what this 4,500 MW is producing or avoiding in terms of GHG, using the QF/CHP Settlement assumptions, and that's the 8,300 Heat Rate, and an avoided boiler efficiency of 80 percent, of the 4,500 MW is net emission reducing of about 2.16 million metric tons. That’s sort of just a snapshot of the fleet as it is.

However, and this sort of gets back to my slide on the assumptions previously that I sort of rushed through, but if we make different assumptions about what CHP is displacing, we can see sort of dramatically different net emission reductions from the existing fleet. So if we think about emission factors that reflect a cleaner load growth in terms our gas-fired generation, and a varying avoided emission for CHP that is consumed onsite, the same set of CHP generators at 4,500 MW all of a sudden is not as clean under these different assumptions. So that's just to illustrate the impact that these assumptions can have on the GHG analysis that we do.

So getting on to the scenarios that we ran, we wanted to look specifically at what was expiring before 2020, since this is the most relevant set of generators.

And again, these scenarios are meant to be illustrative and I'll talk a little bit more about this, but updated data is needed for accurate planning purposes.

So the three scenarios that we looked at were, first, if we retired all of the net emitting facilities above 20 MW, if we just said that 800 MW or so is net emitting, it's not going to be resigned, and it just goes away, what kind of net emission reductions would we get? If we re-contracted all the net reducing facilities, or let 2,500 MW, what kind of emission reductions would we get? And if we repowered some of these facilities, how much closer would the utilities get to their GHG goals under the QF Settlement? And this is just the breakeven curve with the net reducing facilities above the curve, and the net emitting facilities below it.

So under the QF/CHP Settlement, if a facility is completely retired, and this is if the CHP facility completely shuts down, and no thermal need continues, how the GHG accounting is envisioned under the settlement is that it actually does not use the double benchmark, but it takes the baseline emissions of the facility and subtracts out how that power would need to be replaced at a particular replacement energy heat rate that is defined in the Settlement. So, if we looked at these 800 MW of net emitting facilities that I showed before, and completely shut them down, no thermal need continues, and included in there the emissions from the replacement energy, we could get about a .78 million metric tons of reductions from the -- as the IOUs could sort of count that towards their GHG reduction goal.

The second scenario that we talked about was re-contracting all net reducing facilities. So under this scenario, we would use the double benchmark as defined in the settlement, an 8,300 heat rate and an 80 percent efficient boiler, and the calculation is simply by taking the avoided emissions from separate heat and power minus the CHP emissions. So what we've already talked about before, really. What is a CHP producing in terms of emissions, and what is it avoiding if those CHP facilities used separate heat and power, and the difference is the net emission reductions, and we can see a significant amount of net emission reductions from re-contracting on net reducing facilities.

And finally, if we wanted to look at repowering some of the least efficient facilities, so even though a facility may be net emission reducing, it could have a total efficiency of below 60 percent or below 62 percent. If we wanted to say, okay, as a scenario, all those facilities brought their operations up to a 62 percent total efficiency, the way that the settlement would look at this is to use a double benchmark, look at the avoided emissions of the repowered facility, so what is a facility avoiding after it has been repowered and take out what the facility was avoiding prior to the repower, in order to get the net emission reductions. And again, we can see some significant net emission reductions from that.

So I just wanted to say that these scenarios, again, are not comprehensive of all the different things that could happen under the QF/CHP Settlement with the existing fleet. There's many different procurement options for existing CHP and there could be some combination of these three, they're not mutually exclusive; these megawatts could go on a lot of different pathways. And I think that a more detailed analysis is necessary to determine on a project-by-project basis the most likely procurement pathway that a particular CHP facility would take under the QF Settlement in order to determine what type of -- or in order to plan for what type of emission reductions we would get.

So just in conclusion, the potential to achieve -- there's a high potential to achieve significant emission reductions from the existing CHP fleet. And I think that this is really important as we think about targets for CHP going forward because there's a lot of benefit to looking at our fleet as it is right now, our

CHP fleet as it is now, and thinking about how could it be cleaner, how could we get more emission reductions from what we already have? But these emission reductions depend greatly on the assumptions that we make about what CHP is avoiding, both in terms of what is it avoiding in terms of grid emissions, and what is it avoiding in terms of industrial boilers. So, in turn, the potential procurement of new generation to help meet GHG targets under the settlement depends on how the existing fleet is performing. Clearly, the more GHG reductions we receive from the existing fleet, the more limited space there is for new generation to contribute to GHG targets.

I do want to say that the QF/CHP Settlement Reporting Model, where a lot of these calculations -- where all of these calculations are done, will be publicly available. So the model template will be available on our website for interested stakeholders to run both GHG emission reductions and megawatt procurement scenarios. And the first completed IOU reports are due at the end of March 2012, and they will be publicly posted on the CPUC website in April. And then this happens semi-annually on a six-month basis.

Also, competitive -- it's important to keep in mind that competitive solicitation under the settlement is just one of many CHP procurement programs that we have in the state right now, including what is under the settlement. There continues to be the less than 20 MW PURPA program, which is one of the sort of "must take" procurement programs, in addition to the CHP Feed in Tariff Program, which we've heard a lot about today. Under the settlement, there are options of other programs, including an as available program, which is for large facilities making large facilities above 20 MW, but making very small energy deliveries. There is a program for facilities that are called Utility Pre-Scheduled Facilities, and these are facilities that have some dispatchability options, so if you're a large facility and you can be dispatchable, this is another option for you, and then, of course, there's the SGIP Program, which we've already talked about.

And lastly, I wanted to say that we focused a lot on GHG reductions in this presentation, but CHP can have many other benefits besides GHG reductions, which panelists have talked about previously throughout the day. There are benefits for grid reliability, relieving grid congestion, onsite energy sources for the host facilities, bottoming cycle CHP has a lot of benefits, biomass and biogas and other renewable fired CHP has a lot of benefits, as well.

So as we were thinking about targets for CHP, I think it's important to think about what the specific goals are that we're trying to achieve with CHP and really make those targets fit with the goals that we're trying to reach. That is the end of my presentation.

CHAIRMAN WEISENMILLER: Yeah, thanks for the presentation. I was going to say, certainly, again, I would like to congratulate the PUC, the utilities and the co-generators for reaching this settlement. I mean, one of the things we've learned over the decades is you cannot walk into a utility control room with the ISO and see what the heat rate is at that moment, it's something that everyone calculates, the utilities tend to calculate very low values, they tend to look at system Lambdas, they tend to avoid -- to ignore startup and their load fuel, and the co-generators tend to try to find the most inefficient plants and use that as the benchmark. Presumably this number is somewhere in between and hopefully the arguments are over, so we don't want to hear the utilities saying, "Well, gee, this number is too high" because I'm sure that would then provoke every caller to say "it's too low." So it's a settlement, we'll move forward, it's probably good enough for what we need to do. But, anyway, again, I personally was fairly skeptical for a long time that a settlement would occur, but bless you, it did. And as you said, the purpose of this is really to get to greenhouse gas -- you know, we're looking at greenhouse gas emissions. I would say the double -- we sort of bounced that idea here, the double test because, I mean, people for decades have been looking at the total fuel going in, looking at that netting out thermal use, and coming up with an effective heat rate for power. And that benchmark gives you a pretty good easy thing to say, okay, if it's 5,000, which if you do that calculation which I've done for some of the Chevron Refinery projects, it's very efficient and obviously some of the PURPA machines are more nine to 10 and they're just not competitive in today's world. But, anyway, the double benchmark is one way of looking at it, certainly not the only way to look at it.

MS. KALAFUT: Thank you.

CHAIRMAN WEISENMILLER: Again, thanks a lot. Sure, Tom.

MR. CASTEN: Thank you, Tom Casten. Two questions. First of all, in your calculation of the greenhouse gas, if the utility were to purchase VAR support and then, therefore, cut the line losses down, how would that factor into your calculations? Would that generate greenhouse gas the way you're looking at it?

MS. KALAFUT: So specifically how do line losses factor into --

MR. CASTEN: No. You've got a distributed generation plant, nobody buys VARs from it, they start buying VARs from it, the line losses go down by the kind of numbers that Carnegie Mellon has talked about, who gets the credit for the GHG reduction?

MS. KALAFUT: I believe the utility would get the credit for that. I mean, but the thing that you have to think about in terms of what I was just speaking of is those scenarios are really meant for sort of scorekeeping towards the GHG targets under the QF/CHP settlement because the utilities have this 4.3 million metric ton reduction target under the settlement, there are accounting rules that help, that have been put in place and were negotiated during the settlement about how the utilities will get to that goal. This doesn't have anything to do with how allowances are going to be retired, or compliance obligations for the facilities or the utilities, so we have to keep those concepts separate.

MR. CASTEN: Okay. My second question is that you talked about trying to find the CHP that is not net beneficial.

MS. KALAFUT: Uh huh.

MR. CASTEN: But it seems like a binary on or off. Have you looked at the fact that every CHP plant is basically a perfectly thermally matched plant up to some point, and then a straight electric generating plant beyond that? If it's a 91 Btu, a 9,100 Btu heat rate, it's 5,500 Btus on the thermally matched and 11,000 on the other part. So the question to me would not be shutting that plant down --

MS. KALAFUT: Uh huh.

MR. CASTEN: -- but crafting regulations that make it less attractive to run the electric only part of it that's not thermally matched. Is that in your thinking?

MS. KALAFUT: No, I agree. I think that these were simplified scenarios to demonstrate, you know, how some of the accounting works under the QF/CHP Settlement towards these GHG goals. But, yeah, I think there's a lot of ways, even for an inefficient facility, to stay online by doing some of the things that you just talked about.

MR. CASTEN: Thank you.

MS. VAUGHN: Thank you. Beth Vaughn with the California Cogeneration Council. Hey, Jen, just wanted to just clarify one thing and just make sure we're both on the same page, I think we are. But in terms of the accounting, can you go to Slide 17? Right. So I just wanted to make sure people understand, and hopefully I'm understanding this correctly, is in the scenario 2 where Jen has looked at re-contracting all the net reducing facilities that exist, when we're looking at the goals of the 6.7 million metric tons and the 4.3, then, for the utilities, if these existing facilities have no change in operations, so they're already highly efficient, and the utility -- they went in the bids with the utilities -- they're going to come across as a zero, they're not going to be 1.71 million metric tons in terms of counting towards the goal. The goal, that 4.3 is additional installed capacity, so it's the new CHP. So, remember, if there was no change in operations, where you're absolutely correct with the repower, and they've done something to become more efficient, then they count. And I'm looking back at Jerry and Ray just -- just so when people are looking at these numbers, the 1.71 you've got up there is part of the base numbers when you did the calculation back on Slide 12, where you have 2.16 being the total. So just to clarify for David because I know you're looking at some of this information going forward.

MS. KALAFUT: Yeah, that's a really good point, Beth, and thanks for bringing that up. In this calculation that you see on this slide here, that's true, this should be for new facilities coming on, new efficient facilities coming on would use this type of calculation.

MS. VAUGHN: Against the Double Benchmark, right.

MS. KALAFUT: Okay, that's helpful. Thank you.

CHAIRMAN WEISENMILLER: Okay, thanks again. Question? Go ahead.

MR. DAVIDSON: Keith Davidson with DE Solutions. Jennifer, a lot of us in the customer side, co-gen industry have trouble rationalizing the greenhouse gas benchmark that reduces the wholesale CHP plant benchmark by the amount of RPS that's in there. And you wind up -- and I kind of understand the logic and the math -- but you basically wind up distorting or minimizing the value of onsite greenhouse gas reductions relative to wholesale greenhouse gas reductions.

And it's not just -- it's not just CHP, it's all customer side of the meter measures that get reduced by the 20 percent or the 33 percent, and so it would be renewables on the customer side, it would be energy efficiency, all of that, the same logic would apply. And to me, it's a policy consequence that is very troubling when you start saying that the customer side of the measures are worth less than wholesale measures. And I think that's where this thing is leading to, and I just worry that that's the wrong signal you want to send to the rest of the State because, you know, the onsite measures, they've got no T&D, there's so many advantages to onsite DG and energy efficiency relative to the wholesale measures that, to me, it begs maybe some policy changes might be in order. But that's just my opinion.

MS. KALAFUT: Yeah, but I think that from a GHG perspective, if we're just looking at this from a GHG perspective, it is true that onsite CHP may not perform as well as CHP that's exporting to the grid because CHP exporting to the grid is only average displacing natural gas where CHP used onsite is also displacing some renewables. So it has a lower avoided emissions factor. But that being said, again, I don't think that we necessarily need to be looking at CHP and planning for CHP just from a GHG perspective if we want to consider all the multiple benefits that CHP could potentially have. And customer-side CHP lowers the demand forecast and has grid reliability benefits, and so that's something that should definitely be taken into account.

CHAIRMAN WEISENMILLER: Anymore questions, and the general comments on policy we're going to hold to the public comment section. Again, specific questions are fine.

MR. MARTINI: Just wanted to follow-up on what Keith had said, that 100 KW generator that is using the power onsite with a certain efficiency is really having the same effect in the world as one that's exporting 100 KW 100 percent. It seems like it's kind of arbitrary whether you say "these 100 KW displace some renewables and these 100 KW don't." It's all where you put the meter. I mean, literally, you put the meter six feet to the right and suddenly it's exporting, and it seems like the actual physics of the molecules of CO_2 are the same, either way. It's all kind of an arbitrary policy assumption. So I would hate to see onsite measures of all kinds, like Keith said, penalized. So….

CHAIRMAN WEISENMILLER: Next speaker. Thanks.

MR. ALCANTAR: I'm part of Jennifer's panel, so I'm going to --

CHAIRMAN WEISENMILLER: I was just going to encourage you to --

MR. ALCANTAR: How would you like to proceed?

MR. VIDAVER: Actually, I would like if the panel members would take seats behind their names at the table and we're going to post the slide that was sent to us by the representative from Southern California Edison. I'd like to take this opportunity to inform the dais that Public Utilities Commission staff has been incredibly cooperative, staff in general, and Ms. Kalafut, in particular, in assisting Energy Commission staff with an understanding of the settlement and data, etc., so while we can't actually count in interfering in civil service processes, maybe you could facilitate a promotion for her, or more vacation, or maybe just buy her a pony? All right, thank you.

We have a distinguished panel of individuals to talk about what we've just heard and other issues related to the settlement, and utility procurement of CHP, both old and new. And we have Michael Alcantar representing -- well, I'll let everyone introduce themselves, so you've all met Jen Kalafut. Mr. Alcantar, if you could?

MR. ALCANTAR: I'm Michael Alcantar. I represent the Cogeneration Association of California, a coalition supporting cogenerators (inaudible). Thank you.

MR. WILLIAMS: Oh, my name is Ray Williams. I'm Director of Long Term Energy Policy. I sit in the Energy Procurement part of PG&E, that's a part of PG&E that buys electric and natural gas supply for its customers.

MR. TORRIBIO: I'm Jerry Torribio with Southern California Edison. I'm the Manager of Combined Heat and Power Contracts, which is largely involved with implementing the CHP Settlement, signing Power Purchase Contracts and conducting competitive RFO for new and existing CHP projects. Just maybe a question to the Moderator. I sent that slide up here and it's not a slide deck, if that's reassuring, it's a single slide, and I don't know that the other panelists want to have it up there or refer to it, but if I may, I'll just say what it is. It's sort of been up here. This is another way, yet another way, of looking at this issue which has been raised in various ways in the ICF, it looks like it will be raised in the ICF Report: can we get there? Can we get the CARB Scoping Plan reduction? And a couple of the other presentations have raised the question. And it's almost complementary to the breakeven curves, I think, that were in Jennifer Kalafut's presentation. But just for those that are on the WebEx, I'm pointing these things out, I hope you can see them, you won't see the laser pointer, but what we show is three different heat rates which are the prime movers, there's an 11,000 Btu KWh heat rate; there's another curve at 10,000 Btu KWh; and there's finally one at 9,000. And of course, in CHP parlance, we usually think lower is better, so that 9,000 is a good one, and the other ones are higher. And what this is showing on the left axis is totals of megawatts and it's a calculation using the Double Benchmark of how many megawatts would be needed to get the statewide GHG reduction target of 6.7 million metric tons.

And the key thing on this is what's on the horizontal axis, which is the thermal efficiency, the overall efficiency of the project, which is a measure of the application. And so, in our portfolio, existing projects at Edison, we have some that go all the way to the right-hand side, they're up past 75 percent, maybe higher, and then there are some that are down over toward the left-hand number, you get down there toward 50 percent, or 45 percent, and you're getting toward the minimum requirements of the original PURPA rules. And there is in a red line, a vertical red line, is the efficiency standard that we set by Assembly Bill 1613 for the CHP feed in tariff, and the point being that, over there on the right-hand, the higher efficiency projects -- and when we -- how do we get higher efficiency? As was described this morning, I think in the Tecogen presentation, a unit that is intended to run, at least in the example they gave, all the waste heat is recovered, it's not dumped, it is not bypassed, and you might say thermal load following. And then what happens over towards the left, it may be that the projects are electric load following more than purely heat following, but the point is, in the fleet of the future, and what we put together in our CHP program in California, the higher the overall efficiency we can achieve collectively with these projects, the fewer tons would be required to hit the goal, and obviously you'll notice that the heat rate does make a difference, but what is really leveraged there is efficiency. And when the efficiency of the whole project gets below about 55 percent, they kind of go infinite. So it implies that, unless we work in the design of our incentive programs, and unless we work in our monitoring of the CHP Program going forward, and keep track of how it's working, we could be in a situation where you can't get there from here. And this is just some noodling to kind of see what the sensitivities were.

CHAIRMAN WEISENMILLER: Okay, again, thank you. Again, we're not going to get back into the settlement discussions of what the actual emissions would be, but for the cogen, but we'll use the settlement number. So thanks, efficiency is certainly better. But let's move on.

MR. VIDAVER: One of the observations I made while I was standing at the podium was that the megawatt targets could be met by resigning existing CHP resources. Mr. Williams, it's my understanding that PG&E has already re-contracted with some QFs, procuring capacity that would be driven to that target?

MR. WILLIAMS: So before I answer that question, I just wanted to get a feel for how we would proceed. Are Michael and I going to be able to give any opening remarks? Or are we just here to answer questions?

CHAIRMAN WEISENMILLER: Why don't we give everyone a chance for opening remarks, or both of you a chance for opening remarks, and then we'll answer questions.

MR. WILLIAMS: Michael always wants me to go first, so I'll go first. Okay, so within the Energy Procurement part of PG&E, we have a number of goals, first is reliable supply, second is reasonable cost and acceptable cost volatility for our customers, sufficient operating flexibility, obviously, has become more important as we bring in more renewables. We're looking to reduce our environmental footprint over time and, of course, to meet all of our compliance requirements which include lowering order requirements, RPH, energy efficiency goals, and now to meet the obligations under the CHP Settlement.

From this, our responsibility, we really need to take a broad view and look at all of these goals. CHP is an essentially component of our portfolio, it provides an aggregate reliable source of firm baseload supply, and some intermittent supply. The settlement overview itself, I won't get into too much of that because Jennifer already did, but it resolved a whole host of litigation. There is a new State CHP Program, at least as it applies to IOUs, and there is also a continuation of a PURPA PPA for QFs under 20 megawatts.

I would say we should pat ourselves on the back. Michael, CAC EPUC, CEC, IEP, DRA, TURN and the three utilities and the PUC, itself, should be commended for getting together and getting the litigation done and getting a new procurement structure in place. It addressed the policy concerns of at least three regulatory agencies that, in part, is what drives the complexity, PUC, FERC, and the ARB. I'll try to just hit those items that weren't hit previously. There's a new short run energy pricing included. There is a locational adjustment which at least to some degree reflects where a CHP is located relative to congestion. It also adjusts for cap and trade, so when a cap and trade program goes into place, payments to CHP and QFs will go up to reflect compliance costs at essentially a market kind of rate, so we will see that, and that was really a sticking point in the discussions. So, for export CHP, the parties, you know, struck an agreement as to how the payments would adjust as a result of cap and trade. There are five PPAs and pricing amendments, there is -- as we learned, as the utility guy learned -- there is CHP that is in all kinds of different situations, there's some that want to expand, there's some that want a new contract, there's some that want to shut down. And so, part of the complexity here is trying to address the needs of all those various CHP facilities.

Our target is 1387 megawatts by the middle of

2015 and, yes, we have signed up for 186 megawatts so far. And those contracts have been approved by the Public Utilities Commission, so we're serious, you know, we've made some commitments here. Actually, the target for the IOUs, I think, is more like 4.8 and not 4.3, and that is because we have ESPs and CCAs in our service territory. They had as part of this settlement the option of either procuring CHP, or else basically paying the above market cost of these contracts to the extent that there are any, they chose the latter, therefore the reductions themselves, I believe, sort of fall back to the utility because we will essentially be procuring not only on behalf of our bundled customers, but on behalf of CCA and DA customers. You would expect that, because some of this would reflect long run pricing, there will be some above market charges and we would look to allocate those not just to our bundled customers, but to other customers, as well.

We are busy implementing, we've posted short run energy pricing. We've had increase into various contracts, it's a complex settlement, and we have a lot of requirements. The sellers, themselves, have a lot of requirements. We held a seller's conference to help QFs and CHP understand what their options and obligations were under the settlement, and some of them are triggered by the settlement and some are triggered by they sign a new contract, and now they have to go through an ISO process for interconnection. And, you know, it's not a short presentation, but I have a copy of the presentation that we shared and talked through with the seller.

CHAIRMAN WEISENMILLER: That would be great if we can have that in the record.

MR. WILLIAMS: Yes. We also held a CHP RFO bidders conference, well attended, and took feedback and posted responses on our website. And we look forward to receiving bids on the 27th, that's when bids come in for PG&E, the 27th of this month.

For AB 1613, as you know, it's available into CHP that meets the CEC efficiency requirement. The pricing is based on all cost of a combined cycle. Contracts are now available, except, I guess, the one for small 500 KW is not in effect, there was a Protest filed; but the other two are now available. CHP, there is an incentive in place, PG&E did support including CHP in the SGIP Program, and that will take place, I guess, in 2012. Overall, and at this point, you have some questions, and the rest of my comments really go to answering those questions, so I can stop there and then, presuming you ask the questions that are on the page, then I can get back to these other remarks at that point.

CHAIRMAN WEISENMILLER: I guess, Ray, the one question would be, obviously you're in the middle of the RFO at this stage, but I mean, any indications on how things are proceeding? Obviously, we'll be looking forward to hearing after things close, but….

MR. WILLIAMS: It's a little sensitive to say anything right now. I would say that the bidder's conference seemed quite well attended, but beyond that I probably shouldn't talk about what we think the response will be.

CHAIRMAN WEISENMILLER: No, that's fine. I was just going to ask that to the extent they've given us a similar presentation, or a bidder's conference, if they could also put that on the record, it would be good, too, similar to what you've done.

MR. TORRIBIO: Yes.

CHAIRMAN WEISENMILLER: Michael.

MR. WILLIAMS: Oh, actually, I'm sorry, there was one other thing I wanted to do. I talked with Evelyn Kahl at the break and I just wanted to clean up my remarks on EITE, so hopefully I get this right. First is what I understand is for one sector, oil refineries, updates do occur, but on a lagged basis, so there can possibly be recognition of new CHP. Again, it's on a lagged basis, so it doesn't happen right away, only if under common ownership, but not third party CHP. Okay, and then for basically the general practice, or for all other sectors, there is some recognition initially of CHP based on historical emissions, as long as there is common ownership, however, for these sectors installing or expanding onsite CHP is less attractive because historical emissions do not get updated as a practice at the Air Resources Board now. So, you know, you would say that, at least for this group, that this presents a disincentive to expand onsite CHP because the EITE-based allowance allocation would not change. Also, it would present a disincentive if you wanted to go from export to onsite. So I just wanted to make that quite clear.

CHAIRMAN WEISENMILLER: Well, thanks. We should ask Evie if you've gotten it correct. Yes, okay, thanks.

MR. ALCANTER: I was asked by my colleagues to come up here and make things a little bit more lively, and I can see that Ray did such a good job that he sent Cliff home. So I'll have to work a little bit harder.

CHAIRMAN WEISENMILLER: Cliff had to take a call.

MR. ALCANTER: But I wanted to try and take a different tact on what we're talking about a bit, before we get into some of the numbers and responses to what is there. And that is that, as a human being we get up every morning and we have hope, we have refreshed hope, no matter how bad the day was before, we keep hoping. And I think, Dr. Weisenmiller, you and I have been hoping in this industry for well over 30 years, and I think we're still hoping. So today is another day of hope. And I will say that, from comments from my colleagues, as well, I'll share with you that I think this is the first workshop we can remember, in at least our more feeble memories of late, that has actually been on target, on issue, with respect to what we really need to deal with. And some answers that are as blunt as saying, "Tell us, do you want to send the state CHP or do you want us to shut down and move out? It's been that bluntly presented. And I think that's helpful to understand where we're going next.

The other thing, so my second them beyond hope, is reality. I want to talk a little bit about the reality of the settlement and what it does and, more importantly, the illusion of what I keep hearing it does do that I'm troubled by.

And lastly is just the hope that history will be a predictor of our future. And by history, I don't mean the history over the last 15 years because that's been a series of promises not made effective, but the history of this current Governor in his previous term as Governor, had a halcyon day in terms of development of CHP in the State. And it was done to solve a very clear problem that we were facing at the time, how do we get away from nuclear facilities along our coast? How do we get away from building coal plants up and down the San Joaquin Valley? And Distributed Generation was an answer, it happened to be called QS at that point, but here we are today again.

So let me try to give a different perspective than I think you're hearing about what the CHP Settlement does. Ray is exactly right, we were in the woods, and we had more fights and more litigation and more challenges sitting in front of us about what we couldn't resolve than what we could. Those litigations presented real present risks, retroactive rate adjustments, things that could not be tolerated, they would render bankrupt many of the facilities that even I'm operating or dealing with. They had to be resolved. So we dealt with the past. The settlement clearly deals with the past. It then said, "Well, what about these facilities that we're about ready to lose, that for the last, well, since 2002, 2003, we've been pounding the table saying there's no State policy, we're running out of contract time, what are we going to do next?" And some band aids were applied by the Commission at that point in time.

But in 2004, there was the establishment of -- and you'll like this name -- the QF Long Term Contract Policy Proceeding. That was just closed by agreement in the settlement this last time, but we've spent since 2004 trying to figure out if we have a Long Term QF Contract Policy. What we have and what was settled was a contract policy that, for existing projects that either have expired contracts, or expiring projects, which is from Jennifer's numbers, which I agree with, about 3,151 rounded up or down.

We set a figure, negotiated a figure, not all that proud of, that said, well, we'll procure, we'll require, if you will, the procurement of 3,000 megawatts so that at least we're staying static, right? We're treading water with respect to existing CHP capacity. It may be some other project that comes in and replaces, that is more efficient or otherwise, but really what we're trying to do is replace the existing.

When you look at the details of the terms of the QF Settlement, no new project is really going to be competitive with any existing project, they just -- I mean, but good old sure numbers, you know, you're already in the ground, you've already got your infrastructure, you don't have to go through a long queue at the ISO, you're favored if you're an existing project.

So the reality of this settlement is that it kind of held us at the status quo. And what I've been around the state preaching about is the settlement as a metaphor is a pier, not a bridge, and we really need a bridge. And what we need to work on now is the rest of the bridge. I think I'm today changing that metaphor because what it really says is we've walked out of the woods and we've come to the edge of the water, that's about as far as we've gotten. That's all this settlement does. Because, as Jennifer was just telling us, well, if we start playing with the Double Benchmark Standard, if we start looking at efficiencies, if we drive the future based solely on GHG reductions and forget anything else that CHP happens to provide as a benefit, like keeping manufacturing jobs in the state, keeping the tax rolls up, promoting the kind of efficiencies that you want out of these industries to operate, sustaining them in the state to be competitive, if you ignore all that and we just drive based on GHG efficiency alone, we've got a problem.

I mean, by Jennifer's own words today, and I appreciate her work and her candor and honesty, which she's essentially saying, "Well, if we start looking at how the grid efficiency should change, or if we start looking at Jerry's chart and we start trying to figure out, well, who isn't at 80 percent efficiency because those ought to be out of here," we've failed. This settlement fails, to me. It doesn't do what we're trying to do, which is to carry forward a resource that has been essential or tremendously beneficial to the State, that for a number of reasons is disfavored its purchasers, its procurers.

Let's not get overly enthusiastic about the settlement. I'm very enthusiastic about what it did and I'm very proud of what it did, and I think there are some pats on the back about what it did, but it didn't get us out over the water and we need to get over the water and to the other side of the river. I'll be happy to talk about the questions that are presented dealing specifically with issues going forward, as well. Thank you.

CHAIRMAN WEISENMILLER: Thank you. I was just going to give at least one of the utilities, or Jennifer if they want to do a quick response to Michael that would be good, otherwise we'll switch to the questions. Sure, go ahead.

MR. TORRIBIO: Just a comment on maybe getting out over the water. The settlement does include mechanisms with the RFOs to buy power from new facilities. Now, it's been questioned today whether, under short run avoided costs new facilities could be built, but we're talking about the RFO. And I guess I would just point to the experience of the utilities renewable -- the RPS RFOs, where nothing but new facilities are getting built under these, and I would offer a little bit more hope that maybe we have at least one part of the span over the water.

CHAIRMAN WEISENMILLER: Thank you. I think probably part of -- you know, I've heard Michael's speech before and I guess part of the concern on my part is just that the settlement negotiations were pretty much between existing QFs and the utilities, and whoever those future QFs were, you know, they were not going to get mired in trying to resolve all the litigation. But, frankly, at this point let's see what the solicitations do, you know, and hopefully we're getting closer to that point and then we can try and figure out what we have to do next. But at this point, at least I'm waiting to see the jury speak on this.

MR. WILLIAMS: I'll just point out one feature of the settlement, itself. If you're a new or repowered CHP qualified under that part of it, you're eligible for up to a 12-year PPA, whereas existing -- if you don't qualify, you're eligible for up to only a seven-year PPA. So obviously that number 12, you can imagine, there was quite a bit of discussion about that in the Settlement itself. And presumably those 12 years would be sufficient to amortize an investment for at least some new facilities and that does provide an advantage for new or repowered QF CHP relative to those that don't make that investment.

CHAIRMAN WEISENMILLER: Thanks. Thanks for pointing that out.

MR. VIDAVER: Mr. Williams, in his brief discussion of what he's seeing so far on the RFO and can't talk any further about, said that there are existing resources that might shut down, the CPUC's Long Term Procurement Planning assumption is that existing CHP will continue to operate through the remainder of the Decade. It's my understanding that parties generally agree that's the case, but do -- and I'm directing this largely to Mr. Alcantar -- do you believe that there is a risk of a significant share of existing CHP retiring over the next 10 years?

MR. ALCANTAR: Yes. There already has been a diminution of those facilities from contracts that have terminated and people shutting down. There are more strikingly from my experience, many many more potential projects that we have talked about, had evaluated, and they can't even get to the Boards. The advocates in this state who grew up with these kinds of facilities are going to look at programs where they still need processed steam if they're going to operate. There have been -- just, we were counting up earlier today -- there are well over 1,000 megawatts of CHP potential that are now being filled by boilers in the state. So it's already happening in a very negative way. Those are opportunities lost that you don't ever get back, you make that investment in a boiler, it's done, you're not going to come back and say, "Gee whiz, I made a mistake, let me rip those out and put in CHP." So, I think for the future, we already have a problem because we're seeing it presently. We've lost facilities that are coming off of contract that can't go forward under the payment levels that are there and, of course, we're now seeing new contracts that we'll see how that works out because, frankly, many of the contracts that we are seeing right now are inapplicable to the type of projects that are being offered.

MR. VIDAVER: Thank you. Turning from existing CHP to the potential for new CHP, it's the Phase 2 of the Settlement allows for utilities to use least cost/best fit criteria to decide whether to enter into contracts with CHP. I'd like to ask Mr. Williams and Mr. Torribio, Mr. Williams referred to reasonable cost and operating flexibility as two of the criteria of these to logically enter into a least cost/best fit determination, and that the CHP contracts have traditionally provided firm baseload. Can you -- would it be possible in general terms to talk about the characteristics of CHP that would be most likely to meet less cost/best fit criteria, and whether or not you think existing CHP or new CHP is likely to have those characteristics?

MR. WILLIAMS: Sure. If you look at it from a procurement perspective, kind of a product sort of perspective, firm power priced competitively is certainly attractive to a utility. Efficient CHP is going to be more attractive because it will help us move toward the goal. One of the issues in the settlement, itself, was the ability to curtail during low load hours or there's actually a provision in there for some existing CHP to convert to a utility pre-scheduled facility, so they can obtain a contract that way. That certainly can help manage low load hours. But, you know, we are in a situation where electric demand growth is pretty flat right now and where we expect a pretty significant increase in intermittent generation, particularly from renewables. And if you put those two together, you know, we have clearly a -- we're focused on how do we manage that off-peak situation. And so that's part of the reason you see least cost/best fit, we're really looking at that and looking to see how that plays out over the next few years.

MR. TORRIBIO: Just to add, I think the key note is that, just as the utilities -- as transmission and distribution providers are having to operate in quite a different environment in terms of integrating and increasing numbers of intermittent resources, and also dealing with the need to schedule loads and generation, I think the types of CHP projects that will be closest to the least cost/best fit may be to look at it from -- a little different prescriptive than Ray gave -- will be those that help the utility have more agility, more ability to integrate the whole portfolio of resources, and I can recall the first generation of QFs when we could sign up 100 megawatts at a time when we vertically integrated utilities, and it would barely move the needle. And those days are gone. So we're having to maneuver in what I would say are a lot more confined waters, and so the best projects will help us do that.

MS. KALAFUT: If I could make one comment on this, too, David? And it goes back to what Beth Vaughn pointed out from my slide, that she nicely characterized it as a clarification, but it was really a correction to the slide, which is that, if the utility procures an existing facility that is net GHG beneficial under the Settlement benchmarks, that will not count towards their GHG targets; whereas, procuring a new facility that is also net GHG beneficial, will count. So there is an incentive there in terms of some new facility procurement and I hope to see that the RFOs, in addition to least cost/best fit, also take into other even more qualitative factors about what will compete and when in those solicitations.

MR. VIDAVER: Thank you.

MR. ALCANTAR: David, it might also help for the Commissioners to know -- Commissioner to know -- that there have already been filings of testimony by these two utilities and the other, identifying the fact that they need no new baseload generation, certainly, for CHP, so that's today, that's today. Now, I would like to think that will change, but that's what the LTTP process is about, and it's important to understand that what also is critical in the settlement, and I think important for this Commission, but even more important for the CPUC, is that Commission doesn't have to live by the metric of GHG, it can determine that there are other reasons, other policy reasons, other procurement reasons, that they will direct these utilities to procure CHP regardless. And I think that's what I'm here to say. If you want to talk about hope, those are the things that have to happen, given what we're seeing about the kind of analysis, for example, that we see today. If you start sending additional messages to an already skittish investment community looking at these resources, that not only is the metric in question, you're a seven-year contract, you don't know what's going to happen after that, you are already short in terms of being able to ease that debt, this is just the continuing spiral in message about it's time for you to go somewhere else.

MR. VIDAVER: Pursuing this -- I'm sorry.

MR. WILLIAMS: I would just have one elaboration. My understanding of the last Long Term Procurement Plan is that the Commission found no need for any type of generation, whether it was Base Load or dispatchable, and there was no Long Term RFO that followed that proceeding, in this particular cycle.

MR. ALCANTAR: I think you need to go back and look at the current decision on that point. They're still directing procurement for certain resources, it was your utility's position that you needed no resources, that wasn't adopted.

MR. WILLIAMS: Okay.

MR. VIDAVER: The ISO has stated it is beginning an investigation into a resource adequacy requirement related to resource flexibility, the flexible ramping capacity stakeholder proceeding. This would seem to imply an added value to not only the utility, but the system itself for resources that could be brought under the control of the ISO, moved up and down, and Mr. Williams alluded to the need to curtail during low load hours, and Mr. Torribio talked about agility. Are we talking more generally about resources that can respond to either utility or ISO dispatch instructions in order to meet RA requirements associated with ramping, or other requirements that may be imposed by the system?

MR. ALCANTAR: I can take a swing at this one, to begin with. The issue that's counterintuitive to the CHP community is, for years, and even today, be efficient -- be more efficient -- be as efficient as you possibly, you know, use every single bit of your thermal demand in every possible way you can. And now, what' being suggested is, "Well, that's good, but if it doesn't match a flexibility profile, which it can't and doesn't, then you're disfavored. So I would rather be, you know, the old ugly name about a PURPA machine, I’m better off being a PURPA machine with that metric being the decision point about procurement. And that really is counterintuitive. We need to still have the most efficient thermal matching units we possibly can, and what's happened, thankfully, from a long litigation with the California ISO, that FERC ordered that, as long as there was as demonstrable thermal match by the host, you could not physically curtain below that designated level, so you've got some protection out of the so-called QFPGA. But that very protection, if you're saying, well, no, I want flexibility to ramp you off and on, it again is counterintuitive to the process. Now, the other aspect of your question that is important is, under the settlement and under the settlement contracts, the product, the very minimum product that you sell, comes with three components -- capacity, associated energy, and the affiliated RA, all RA requirement go with it, so you don't have other RA to sell out of that capacity as it may be otherwise delivered. It's delivered with the product that you're bidding and selling in and providing. So you don't have the commercial flexibility to deal with that as a distinct product.

MR. VIDAVER: Lastly, the ARB assumption of a 50-50 split between onsite generation and export would seem, if only based on Mr. Darrow's conclusions, to largely be accurate if you have export incentives and, as a result, you end up with rather large amounts of CHP. He reaches the Governor's target in 2030 in his high case, or comes quite close to it if my memory serves me correctly. Is it reasonable to assume that, if you have a planning assumption that yields a substantial amount of CHP -- I don't want to say what I think substantial is -- but if you were talking 3,000 or 4,000 megawatts, that a 50-50 split between onsite use and export is reasonable, but if you're talking a scenario in which you only get 1,000 megawatts, you're talking about a 90-10 split towards onsite consumption. This is of interest to the Energy Commission because of the way we treat the load forecasts.

MR. ALCANTAR: There are two criteria drivers here, one is thermal match and one is electric match. The thermal match resource -- and I'll help Jennifer out here with one of her earlier comments -- the largest single CHP facility in the west is at the previous ARCO, now BP, called Watson Cogeneration Company, it's -- I think the nameplate there is roughly 419 megawatts. It's thermally matched. It was sized to meet its thermal load. If you look at another project that's familiar in this room, the Richmond Refinery, that facility always built essentially to meet a lumpy load growth thermal demand at its facility and it stayed behind the meter as much as it could, and often had some amount to sell as it was moving in. Those two differing dynamics tell a wide variety or tale about whether or not you can assume that there will be 50 percent usage behind the meter and 50 percent export. It's highly variable. For example, in the Watson situation, early on in their initial operation, they were exporting well in excess of 300 megawatts. That’s far less than 50 percent, and yet if you look at Richmond, I would say that were exporting at times close to zero, or a very small fraction of their total capacity. So you know, there's no tried and true operation or presumption there unless you start saying, "What I want to do in this state is have thermal matching and as much efficient energy production from those resources as possible," and you incent that to happen.

CHAIRMAN WEISENMILLER: Yeah, no, I think if you actually look at the AFCs for El Segundo and Watson, they both have roughly comparable steam loads. Having said that, as Michael said, one is sized at 450 and the other is sized at roughly 100, and that's why when you do that, having said that, El Segundo has a remarkably low effective heat rate. But, again, it's different corporate philosophies at the time.

MR. VIDAVER: We do have one question that went out with the agenda, which is what do you think an appropriate planning assumption is for use in an LTTP Proceeding? And I would suggest that, unless somewhat wants to opine on that subject, that we might ask you to answer that in written comments. But if you want to take a shot at it now, go right ahead.

MR. WILLIAMS: I'd like to take the liberty to make one comment about 1304 and then maybe try to address that question -- try to frame the question because I can't answer it. So, the first is on, you know, I think as we move through implementation and we have new contracts and new projects, monitoring or measuring the actual efficiency of CHP, I think it becomes more important because that gives you a better feel for how are you doing in terms of reducing emissions, how are you doing in terms of their efficiency, and the CEC itself has a 1304 Form and I believe it's in Schedule 2, Part A, you could ask some very simple information: what's the fuel input and type in MMBtu? What's the electrical output in MMBtu? And I believe you can find those in other parts of the form. But the one that's difficult is what is the used thermal output in MMBtu. And if that question could be asked simply and directly in a revision to 1304, I think that would be helpful because you generally survey a much broader part of the CHP community than, for example, PG&E will in its report that we'll file soon. We're really looking at what's in PG&E's service territory, so -- we'll add some additional detail in our comments.

Now, to go back and try to bravely answer your question, I talked to the people who are involved in the resource planning side, and you know, what we have a good picture of is, you know, what's going to happen in PG&E's service territory based on what we contract for. So we can't answer the question for the state, and we really can't look at contracts plus onsite, we don't see that. So it's pretty much a guess, but a decent range might be in the year 2020, 400 to 800 megawatts nameplate and, you know, economic conditions have a lot to do with this, as well as maybe some of the policies going forward. Now, if you look at that from a resource adequacy perspective, you might get 80-90 percent on peak availability from that nameplate, so from that RA perspective which is kind of what's important from a procurement point of view, you're at 300 plus to 700 plus as a range. Now, onsite vs. export, I don't think we really have any idea, I think probably Michael has much more insight into that than PG&E would, so that's probably as much as I can share at this point, as much as I know.

MR. VIDAVER: This is for the PG&E service territory.

MR. WILLIAMS: Yes.

MR. ALCANTAR: And, Ray, do you happen to know if that's net new incremental over and above existing embedded CHP capacity?

MR. WILLIAMS: Yeah, I think 400, 800, or let's say 300 plus to 700 plus, it's a reasonable guess for new for PG&E service territory in the year 2020, this is just conversations with resource planners and this is the number that they threw out there.

CHAIRMAN WEISENMILLER: Yeah, coincidentally, in OII 26, PG&E's number was about -- actually, three significant digits, but it was about 600 something, in contrast to the Governor's goal of 6,000 in how much it got.

MR. WILLIAMS: Well, at least I'm happy I'm within the range of what PG&E previously provided.

CHAIRMAN WEISENMILLER: That's right, yeah. And actually, in terms of some follow-up questions, in terms of the types of projects, getting back to what Dave said, one of the things that tends to drive the export vs. onsite is gas prices. And typically what we saw was, when people expected very high gas prices, that then the efficiency benefits of cogen tended to drive people to be sizing projects to do a lot of export, but as -- you know, if you just think that you have an efficiency wedge, that's obviously much more valuable at, say, $6.00 than at $3.00. You know, and certainly whenever you do cash flow modeling of a cogen project, if you double the gas price, it's going to look a lot better no matter what the number was. So that's one of the things that will affect that export, although obviously in California, you've got times when gas is on the margin and times when non-gas is on the margin, and the cogen can't compete effectively with hydro or other things, so it either has to become dispatchable or, you know, you've got to figure out some way not to be competing against, you know, dump hydro from the northwest, or other non-gas resources. But the other thing that you tend to see is, when gas prices are low, is that the expectation is for increasing power prices, that ignoring the sort of exit fees, or type of things like that, tend to really drive projects more towards onsite. You know, again, when Chevron was investing, say, in Richmond, it was a very simple calculus to say, "We think gas prices are going to be flat in the near term, but we think power rights are going up." And so it was locking in that hedge. So, again, I think as we look at these, it does get back to what you think is going on in fuel prices and what you think is going on in power prices. So, as you think about how to respond to Dave's question, one of the things to think about is what your projections are for future gas prices and future power prices, particularly in that sort of industrial commercial classes.

MR. VIDAVER: I'd like to thank the panel for their time and effort and encourage them to file written comments on the questions I've raised, and other questions raised throughout. And if there are questions from the room or from the phone, perhaps now is the time to take them.

MS. KOROSEC: We do have one question from the WebEx. We have David Erickson.

MR. ERICSON: Hello, can you hear me?

MS. KOROSEC: Yes, we sure can. Could you step away from your computer because we're getting feedback from the time delay.

CHAIRMAN WEISENMILLER: Or mute your -- anyway, if you're on a speakerphone, please get off the speaker.

MR. ERICKSON: Okay. Is that still a problem?

MS. KOROSEC: No, that's much better, thank you.

MR. ERICKSON: Okay, the question is, if a community choice aggregator is considering possibly constructing new CHP as part of a local portfolio, do you see the procurement or the GHG emissions reduction being handled differently than what the IOUs have been discussing? Or how do you see the overlap with the IOU issues?

MR. WILLIAMS: So this is Ray Williams from PG&E. As part of this settlement, we sort of built in the option for CCA and DA representatives in total, to either assume a portion of the CHP obligation or, instead, to pay the anticipated above-market costs of particularly the longer term contracts. The representatives of those groups chose not to purchase CHP, but instead to pay the above-market cost. So, to the extent, now, if you had a CCA that wanted to actually build or buy CHP, I don't see that as part of that settlement the megawatts would necessarily count because of the election that was made at the end of the settlement by the CCA and DA representatives.

MR. ERICKSON: Okay, that's very interesting because that implies, then, that the settlement would have to be revisited in the case of, say, new CCAs that started that may want to handle CHP differently.

MR. WILLIAMS: I think process-wise, you would need to petition the PUC and the decision that adopted the settlement.

MR. ERICKSON: Okay, thank you very much.

MS. KALAFUT: And this is Jen Kalafut from the CPUC, just on this point, I mean, I agree with what Ray said, but I think the decision to build a new CHP facility within a CCA District, you know, may not only be contingent on whether or not it's counting towards the IOU megawatt or GHG targets, but you know, there are a lot of benefits that a CCA could see from developing a CHP project, including avoiding carbon costs in wholesale prices that are purchased through the IOU.

MR. ERICKSON: Right. I guess that was probably more specifically -- what my question related to was not so much whether the benefits would count toward the IOU procurement, but whether -- or how it would be handled in the context of the CCA contribution to meeting the AB 32 goal, if that makes sense. Does that make sense?

MS. KALAFUT: Yeah, and in terms of contribution to the AB 32 goals, again, if the CHP is lowering the total emissions profile of the CCA, that's going to -- I can't speak for the ARB and how they're accounting for this, but I would imagine that that would count towards AB 32 goals for CHP.

CHAIRMAN WEISENMILLER: Yeah, let me encourage you, in terms of if you have specific suggestions in this area, that you file those as part of your written comments.

MR. ERICKSON: Okay, thank you very much. I will do that.

MS. KOROSEC: We do not have any more comments from online speakers.

CHAIRMAN WEISENMILLER: Is there anyone else in the room who wants to comment? Sure. Please identify yourself.

MR. WOLFIT: Greg Wolf with NextEra Energy and I had a question for Ray regarding, I guess, 487 megawatts, or whatever the number was, that had been re-contracted, and the general feeling around any of your Sellers Conference regarding the risks of energy imbalance and the new risks that appear to be in place under the new contract that's being offered vs. the old QF Agreements.

MR. WILLIAMS: Actually, I'll speak to it, but my guess is Michael is probably going to correct some of the things that I say, but to the extent when you sign a new contract it moves you into ISO tariff requirements, then there are new obligations that a CHP generator has. One of them has to do with scheduling. I believe the utility could offer that service, or they could get it through some third party. And I'm sure there are other obligations, as well, and I would be happy to sort of pass the baton here to Michael to complete the answer.

MR. ALCANTAR: If you do not use the utility as a scheduling coordinator, you do expose yourself to a wider array and deeper array of potential imbalance charges, so the way the pro formas are written, it's highly encouraging incentives to make you elect the utility, your interconnected utility, as your scheduling coordinator. Having done that, then, no matter -- either way -- you are truly at risk if you fail in any 15-minute interval to be extraordinarily careful about communicating any real time changes to your day ahead hourly schedule because those will expose you to imbalance penalties if you haven't informed your scheduling coordinator so they can correct them.

CHAIRMAN WEISENMILLER: Sure.

MR. NEFF: One last comment or a question on the 3,000 megawatt target. Once that target is reached, does it have to be maintained? Or is it just a single, you reach it, and then you have no other further megawatt pulls?

MR. ALCANTAR: Absolutely. It can't be backed off. I think there's a dispute about that right at the moment in terms of county rules, but in my view? Absolutely. It's to be maintained and sustained. And the question then becomes how do utilities administer that, how the CPUC accounts for it.

MS. KALAFUT: Well, I think it's important to keep in mind that the -- and correct me if I'm wrong here, Michael, or anyone else -- but that the megawatt target is by 2015, 48 months from November 2011, so November 2015. And at that point, that's when the 3,000 megawatt target will be assessed. There's nothing going to be signed -- I mean, between now and then, there's nothing going to be signed, necessarily, you know, less than four years. I mean, there's potential for that to happen, but if something -- if a facility signs up a seven-year contract, then it expires in 2017 or 2018, those megawatts would still count towards the megawatt goal.

MR. ALCANTAR: I think the difficulty with that counting mechanism is that you've failed to maintain another metric in the settlement, which is you are to sustain the GHG benefits associated with the retained fleet. And so you've got another issue to try to address in that county. So I would argue, no, if that expires you've got to make it up in megawatts because you've got to be able to recount GHG to get there.

MR. TORRIBIO: I would question that interpretation. I believe it's counted at the time of execution of the contract, I don't think it says anything about in perpetuity, or follow-up monitoring of the megawatt total.

MR. ALCANTAR: So if that were the improper interpretation, Jerry, we have an instantaneous 3,000 mega -- you could sign 3,000 megawatts for a day and the end of the program occurs, so that doesn't seem to be logical to us. But we can deal with it.

MS. KALAFUT: But this is being worked out in the accounting and reporting rules and template that we're putting in place right now, so we will have this worked out by the end of March, before the first reports are due. Okay.

CHAIRMAN WEISENMILLER: Okay. If there are no other comments, I'd like to really thank everyone in the room, with the last interchanges, encouraging to hear a dysfunctional family in this area is still somewhat dysfunctional, although not as much as in the past. But again, I think the basic message is that certainly this

Governor and this Administration, you know, really want to see cogen move, and are really looking for the utilities to bring in creativity and initiative to really move these programs along.

And certainly, again, from part of our conversation today, I think certainly looking for ways that we can find additional value in cogen, you know, I know the typical is Base Load, but obviously those of us who worked for Crockett know that you could have a project that is shut down every night, you know, and still meets its steam loads, and its PURPA requirements, and actually provide VAR support, and provides VAR support to PG&E. So one can get creative. I certainly would encourage people, particularly on the ends of some of the transmission lines, to think about ways to get projects there, you know, to enhance the reliability for places like 29 Palms, or -- I think that was one of the original drivers for Trona, or I can point to any number of projects in the '80s which, at the end of transmission lines in the cogen projects really enhanced the service and it was certainly avoiding, you know, major upgrades to the distribution or transmission system that, again, if we can do that, it helps, so if there are ways that they can provide ramping, although I hadn't -- until Michael mentioned it, I hadn't thought about the RA issue, and I'm sure the contracts basically say it's already contracted out. So, again, it may be that you need -- you know, one of the features of the '80s obviously was just standard offer and then everyone tried to find ways to tweak the projects, tweak the contract and provide somewhat more value going forward. And presumably -- hopefully the negotiations in response to the RFPs will allow some creativity to tweak the contracts and get some additional ratepayer benefits out of them. So anyway, Andy, excuse me, do you have a comment?

MR. BROWN: Yes, thank you, Chairman. Andrew Brown with Ellison, Schneider and Harris. I didn't realize you were trying to close out the public comment period. But I'm here on behalf of two entities, one is Ace Cogen and the other entity, or actually, the Rio Bravo Poso and Jasmine entities. These are a handful of the solid fuels, the QFs that exist in the state. And the advance of the GHG program obviously put these facilities in a bit of peril. Ace Cogen itself is located out in Trona at the end of the line, and it was sited by this Commission in an effort when the state was fostering fuel diversity and actually was encouraging coal and petcoke-fueled projects. We now find ourselves on the other end of the pendulum swing, where these types of projects are being encouraged to go away about as quickly as you can.

They are trying to look at options and the CHP program potentially is one. But, as you can imagine, the way that these type of assets will achieve a more preferred GHG emission profile isn't by enhancing efficiency of the projects, it's by fuel switching. And, unfortunately, CARB, despite a few pleas and efforts on our part to have a transition pathway developed for the fuel transition for these types of facilities, that was never laid out as an option. And so now we're trying to manage to find a path to make significant capital investments that are required for fuel switching.

Now, Ace is tied to an industrial facility that also is operating its own coal boilers in the facility itself, besides providing thermal energy on a continuous basis, also functions as a backup to the industrial site's facilities because, if the industrial site's facilities fail, then it's entire industrial operations sort of literally seizes. And so the transition from coal, petcoke solid fuels to natural gas will have a large bit of infrastructure and planning involved with that.

Not quite similarly, but not dissimilarly, the Rio Bravo, Jasmine and Poso facilities are solid fueled, they're located in assisting in enhanced oil recovery, so there's a little bit of a different nature in the industrial activity; they're in the process right now of looking to convert some of their fuel handling because they're locating in the location where they can take advantage of some biomass opportunities.

But, again, this is a handful of projects the state originally had, no pathway for a fuel conversion, which is the way to get the desired GHG profile in place, was developed as any part of the state's AB 32 process.

So whether or not they're considered new or existing CHP, or things that we'll be looking into in terms of participating in the utility CHP Programs, but I wanted to point these out to the Commission today because I think they're examples of projects that were developed with the CHP and efficient use of fuels, those policies in mind, and now they're really being orphaned by the state with the change of environmental policies.

And it would be most helpful if there was a transition pathway that wouldn't cause a significant economic dislocation for these projects, the folks they employ, and the localities which benefit from their injection of taxes, etc.

CHAIRMAN WEISENMILLER: Okay, thanks. Any other public comment either in the room or on the phone?

I again thank all the speakers from today and certainly the staff for organizing this, and this meeting is adjourned.

[Adjourned at 4:49 P.M.]