BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of	)	
	)	Docket No. 13-IEP-1M
2013 Integrated Energy	)	
Policy Report	)	Workshop Re:
(2013 IEPR)	)	Bioenergy Development

Status of Bioenergy Development in California

California Energy Commission
Hearing Room A
1516 9th Street
Sacramento, California

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9:00 A.M.

Reported by:
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 - Moderator
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Kim Carr, Sierra Nevada Conservancy
Peter Tittmann, Center for Forestry at U.C. Berkeley
Kevin Bundy, Climate Law Institute, Center for
 Biological Diversity

Others Present (* Via WebEx)

Evan W.R. Edgar, California Refuse Recycling Coalition
Michael Theroux, JDMT

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P R O C E E D I N G S

JUNE 3, 2013 9:06 A.M.

MS. SALAZAR: Good morning, everyone. We're going to be getting started. Thank you all for being here at the Energy Commission's 2013 IEPR Staff Workshop on the Development of Bioenergy in California.

Before I get started, I need to read a couple of notes on housekeeping rules. Just for those of you that are not familiar with our building, we do have some restrooms located directly outside the Hearing Room and directly to the left; there is a snack bar on the second floor under the white awning; and in the event of an emergency and we are required to evacuate, please follow our staff to the park directly across the street and we'll reconvene there until we've been given the all clear sign.

Today we're going to be listening to industry experts and the utilities. We are going to be providing an assessment of California's progress towards the objectives outlined in the 2012 Bioenergy Action Plan, so the results of today's workshop will be informing staff for this development, as well as the discussion on the

2013 IEPR.

One of the things that we wanted to remind you is, as we're discussing the topics today, if you can please keep in mind not only are the challenges important to us, we really want your feedback on some solutions or ideas for solutions and any other comments you may have.

Today's workshop is going to be divided into three sessions, our morning panel will be on the Biofuels, and we have Jim McKinney here from our Fuels and Transportation Division. We will be taking comments and questions after each session and what we're going to do is take comments and questions from the room first, so if you can step up to this center podium and please speak clearly into the mic so that we can get it recorded, please state your name and your organization, and if you wouldn't mind handing a business card to our Court Reporter so he can capture that correctly.

After lunch, we have Session 2 led by Garry O'Neill Mariscal, and he'll be going over the Biomass to Power Challenges and Opportunities. We'll take a quick break, and our final session will be on the Benefits and

Environmental Considerations.

We had six objectives outlined in the 2012 Bioenergy Action Plan: 1) to codify legislation and issue formal executive direction on the increased biomass through in-state bioenergy and biofuel development; 2) to facilitate growth of the bioenergy industry here in the state, making the regulatory permitting process more efficient for project developers and permitting officials by eliminating redundant and conflicting regulatory actions and requirements; 3) developing front end processing standards to ensure that recyclables are removed before bioenergy production; 4) allocating a significant portion of EPIC funds to RD&D and emerging technologies; 5) increase development of community scale forest-based biomass facilities; and 6) allocating funding for R&D advanced conversion of technologies needed by the 2018 compliance for LCFS.

Just a reminder, you can find the materials for this workshop. We know that there are probably a number of presentations missing at the point, but it will be posted within the next day or so at this address.

And also, a couple of the policy drivers, we have our 33 Percent RPS; SB 1122, which will be discussed in our second session; the LCFS, Low Carbon Fuel Standard; and Climate Change and Adaptation. And I was also told, let's see if I have that, that the ARB will be having a workshop -- I do not have that, I'm sorry -- they'll be having a workshop coming soon on June 13th. So if you are able to, please tune in for that discussion.

And finally, we also have -- CalRecycle has goals on diversion, we are currently, I believe, at 50 percent and that will go up to 75 percent by 2020.

We are accepting written comments; they are due no later than 5:00 p.m. on June 17th, be sure to include the IEPR number and title "Status of Bioenergy Development in California" in the subject line, and submit those electronically to our Docket Unit, the address provided here, as well as our Technical Lead, Garry O'Neill.

And with that, I'm going to call Jim McKinney up to the podium.

MR. MCKINNEY: Good morning. Thank you, Rachel, thank you Garry, for including the Fuels and Transportation Division in this part of the IEPR Workshop on the Status of Bioenergy in California.

My goal with this presentation is to provide you with kind of a big picture snapshot overview of the Biofuels industry in California. The panelists here are all experts in their field, and each of them is much more knowledgeable than I in their respective fields. So it'll be really interesting to hear what they have to say. So I'm just going to try to set the stage for you going forward.

So just to set the stage for you here: we are a very large economy and a very large transportation and fuels economy, so I think most of you are familiar with these basic stats, our population is pushing 38 million, our GDP is pushing $2 trillion, a big contributor of climate change emissions at the global scale, and unlike many other parts of the country, here because of our relatively clean resource mix, transportation figures largely in our inventory, so we're over 40 percent of the GHG emissions in California.

And really, the big drivers are the size of our fleet, so over 26 million passenger vehicles and nearly one million trucks, Class 3 and higher, so those are heavy-duty pickups and higher. Fuel consumption: we are one of the largest fuels markets on the entire planet, so gasoline is about 15 billion gallons of gasoline consumed annually, and that includes Ethanol at about 1.5 billion gallons, it's what we call the E10 blendstock. The diesel side, just for on road transportation, it's over 3 billion gallons of diesel fuel.

So this is kind of my best estimate with the data we had available to provide you a snapshot of current conditions. So at commercial scales, or industrial scales, there's really not a lot of action in California right now. For ethanol, we have in-state capacity of about 240 million gallons per year spread across five plants and four companies. Production, the capacity factor is lower, so 170 million gallons per year. But the total demand, again, is 1.5 billion, and Mike Waugh might have some better statistics than I do on that, but it's roughly 1.5 or 10 percent of the total supply and that's primarily Midwest corn, so corn ethanol from Midwest corn feedstocks, imported by Unit Train to the refineries here in California. And the driver here is really not so much carbon reduction, but it's air quality considerations, so ethanol is a substitute for MTBE as an oxygenate for gasoline.

On the biodiesel side, about 46 million gallons per year in-state capacity spread across 12 plants. Production is now at about 26 million gallons per year, and while that seems modest, it's much better than the 10 million gallons per year we had just in 2010. It's a relatively small market demand.

And I took a liberty here because we just learned about a month ago that Neste Oil, which is based in Finland, has constructed three very large industrial scale renewable diesel plants, so there's one in Singapore, one in Rotterdam, and one in the Helsinki area. The Singapore plant is now up and running and we learned earlier that they have contracts with as yet to be named oil majors here in California for 100 million gallons of renewable diesel product made from waste greases and tallows from Australia and New Zealand, so they have sidestepped the oil palm controversy that bedevils most of the producers in that part of the world. So I took a liberty and just had total demand here at 126 million gallons per year.

I'm going to kind of switch now to our program, the Alternative and Renewable Fuel and Vehicle Technology Program. This is a program shared by the Energy Commission and the Air Resources Board Mobile Sources Division. And basically this is an incentive complement to some of the carbon policy regulatory drivers that we have in the state. And Rachel mentioned LCFS, LCFS is a subset of AB 32, LCFS is an early action item, and as she said it calls for a 10 percent reduction in carbon in the transportation sector. We cycle at about $100 million a year in funding in the Mobile Sources Division at ARB through the Air Quality Improvement Program, cycles from $30 to $40 million primarily for vouchers for light-duty electric vehicles and commercially available hybrid and electric drive trucks.

Here's our list of policy drivers: So, again, AB 32 sets the Carbon Reduction Goals, so it's about 30 percent reduction by 2020, and then 80 percent reduction by 2050; Petroleum use, 15 percent reduction; In-State Biofuels -- and I don't know if these stats are still current -- they're not, so my apologies, but we want 20 percent of Biofuels used In-State by 2010, but those have been revised. The LCFS, we've talked about. The RFS2, so this is the Federal kind of volumetric equivalent of the Low Carbon Fuel Standard, this is a big driver now for biodiesel production in California. Air Quality, this is an emerging issue in order to meet Federal Air Quality Goals in the San Joaquin Valley and L.A. Basin, which are in severe non-attainment for NO_x. We need 80 percent reduction from current levels by 2023, so this is a new challenge. The Governor's ZEV Mandates will accommodate one million electric vehicles by 2020, and an additional 1.5 by 2025.

Our program has a sustainability provision. As this program was coming together, there were a lot of concerns about deforestation in Southeast Asia in response to European Commission directives for biodiesel content. We were seeing similar concerns in the Amazonian Basin around cane ethanol. This slide here used to be a rain forest in Indonesia. And in North

America, we saw that with the very rapid conversion to corn, basically creating a giant monoculture to drive one feedstock and one fuel product for consumption in North America. So we've cycled about $390 million in grants thus far from 2009, about 240 projects, and I've highlighted biofuels investments. We've got about $123 million across 46 projects to date.

So you can see here, there's about $90 million allocated to biofuels production, so this includes about $20 million for biodiesel, about $50 million for biomethane or biogas, another $20 million for ethanol. We have a modest amount in fueling infrastructure, so about $20 million for E85 retail station development in California, and about $4 million for infrastructure, what we call upstream tankage infrastructure for biodiesel.

These are some of the strategic goals that we have for our investments in the biofuels sector. So first and foremost is really to move California away from this initial dependence on first generation biofuels, so that's corn-based ethanol on the ethanol side, and soy-based biofuels, both of those are food stocks, there's lots of great debate and controversy about the role going forward in North America for biofuels, but our goal in California is to move away from those as best we can. We want to build a capacity of California firms to produce second and third generation biofuels using advance process technologies, and waste-based and alternative feedstocks that do not compete with prime soils and foodstuffs. And we really want to leverage the knowledge, technologies, and feedstocks from the current biofuel production base. So the California companies who built the ethanol biorefinery fleet and raised over $500 million in private capital, to get that set of investments up and going, and that's just critically important. And the biodiesel has done the same, industry has done the same on its side.

And I'm going to show you a slide from an old report from the U.C. Davis Biomass Collaborative and, Nathan, maybe you could say in your talk if this is still current or not, I've heard it's an old slide. But we estimate roughly 2.7 to just over three billion gallons a year can be made from the feedstocks listed on this page. So you can see agricultural residues, animal manures, FOG, so that's Fats, Oils and Grease, food waste. Biomass is a tremendous asset here, it probably won't be realized due to the economic considerations and the challenges of really getting the processing equipment up into the Sierra and Northern Cascades where the fuel loads need to be reduced or, conversely, getting that feedstock material down to processing plants at an economical rate. Landfill gas, MSW, wastewater treatment plants, so you can see a pretty big range of potential numbers there. And I think one thing that is important about this is that no single number really stands out. I don't think the future in California will be, you know, one technology and one feedstock that are going to satisfy the demands on the diesel and gasoline sector for substitutes. It's probably going to be a mishmash of regionally available feedstocks and the appropriate process technologies.

In terms of our own biofuels funding, about $50 million has gone into biogas, and I've got some other slides coming up, I'll go into these in more detail. It has a very low carbon intensity value of 11 to 13 grams CO_2 equivalent per megajoule, and that's the metric we use in the fuels arena. So that's about 90 percent below the baseline for gasoline or CARBOB and diesel here in California.

Biodiesel/Renewable Diesel, we got $21 million over 11 projects. Again, with the waste-based feedstocks also very low carbon intensity values, so this will take on increasing importance as the carbon markets mature and that big differential in carbon is recognized through the LCFS and RFS2 carbon markets. And then, for Ethanol, another $20 million spread across seven projects.

That was kind of one man's view, or our program's view, of these different things and, again, I think the panelists will have very interesting insights into each of these areas.

But in terms of Ethanol going forward, one thing that we're seeing now is just some of the risks and limits with a monoculture of feedstocks, so, because of the very serious drought that's been occurring in the Midwest, we have a shortage of grain and we have very high feedstock costs. One other thing that this has done is create competition with different feed grains, especially on the poultry side; on the dairy feed side, or livestock feed side, there is a byproduct called distiller's grain which is basically the wet remains after the starches and sugars have been removed, and that's a very high protein feed supplement for cattle, but poultry like their feed in the kernel, kind of the dry kernel, so that's a direct competition.

And there are limits to the arable land and feedstock availability in North America and globally. Next, you know, one of the great promises for ethanol has been cellulosic process technology, so that's whether it's an enzymatic-based or acid-based process technology coupled with waste-based feedstocks. That really has been the potential, but it was the potential when I started in this field, and it's still the potential. So getting these technologies down to commercially competitive costs is a true challenge, but there's a lot of continuing work in there.

Another challenge for California ethanol producers is competing with the economies of scale that the Midwest corn ethanol industry can bring to bear, and now the Brazilians with their sugarcane ethanol. Again, both of these are very sophisticated industrial processes and they have very active kind of trade associations and, again, the way they continue to develop the technology drive-down costs, drive down the carbon content, is impressive. And it's hard for smaller companies, especially at the start-up scale in California, to compete with that.

E85 was supposed to be a promising outlet and market driver for ethanol in California, but a couple things, one is just an expensive product and E85 sales are relatively flat; our primary contractor to build E85 stations in California is going far more slowly than we ever thought. And it also just has far less energy density than gasoline, so consumers need to make their own choice. We have about 400,000 flex fuel vehicles in California, but very few of those are using E85 ethanol.

Quite importantly, we really need these carbon markets to mature, and I look forward to Mike's presentation. We're seeing the benefits of that on the Federal side, as I said, with the RFS2 credit levels for diesel, biodiesel, that's really starting to drive production in California.

Looking to the future, again, cellulosic and drop-in fuels, those technology costs need to come down so they can compete with the primary feedstocks.

And just as an example of what one company that we're funding is doing, there is the Mendota Beet Cooperative project and theirs is down in the San Joaquin Valley, and what they propose to do is to take sugar beets which were grown historically in California for sugar, take a smaller acreage of that and use that as a primary feedstock for ethanol production, but they want to do what's called an Integrated Biorefinery, so there's also going to be Ag waste and so you're going to have fermentation, you're going to have cellulosic process technology, and then you're going to have anaerobic digestion of some of the remaining waste streams. And the result there will be a near carbon neutral series of ethanol products and gas products. So that will be interesting to see how they develop that and how that works out.

Biodiesel and Renewable Diesel, so again, because of the RFS2 drivers that are coming out with the credits, California producers are rapidly expanding production in existing plants.

We've made three recent awards at the commercial scale. As I said, I think a lot of these are going to be kind of regional niche markets moving forward.

CI values, as I said, very low from 11 to 17 grams CO_2 equivalent per megajoule. And this is really a nice transition away from soy as a primary feedstock. I mentioned the oil palm feedstock controversies from Southeast Asia. And one other thing, too, that the biodiesel industry I think has resolved and fixed are the initial fuel quality problems that we had with first generation biodiesel, so there was a new ASTM standard, and that producers are meeting that.

And really looking into the future, there are several things, so one is the algal or algae-based fuels, so for example, U.C. San Diego has got a research consortium and a company called Sapphire down there that are working aggressively to bring this type of fuel to market.

The Neste Oil project from Singapore, I already mentioned that and, again, I would put that in the game changer category. If those numbers hold up, they will essentially quadruple the supply and demand for biodiesel here in

California. There are also some very important emerging markets in the aviation sector and an off-road construction. So, for example, the military has an active funding and research program for advanced biofuels and there are several jet fighters that are using -- I don't know if it's Solazyme or Novozymes products on a test basis. Boeing is also doing trials for its fleet of airliners.

So for this industry sector, there are really kind of three main producer groups, one are the traditional biodiesel producers and they're now getting into waste-based feedstocks. You then have the renewable diesel industry and this is a product where you take a feedstock and run it through the hydrocrackers at a classic oil refinery, and you get a product that's chemically similar, if not identical, to diesel, so it's fully fungible so we don't have to mess with parallel infrastructures anymore. And then, third, and I'm looking forward to I think Paul's presentation from Novozymes, we have the Advanced Technology Bioengineering firms such as Solazyme, Novozymes, Amyris, and Sapphire. And to me, that's probably the future of this industry in

California.

On the biogas side, now currently production is relatively low and this is an expensive product to make. A couple of important factors here, one is there's no access to the pipeline distribution system yet, and we had a good workshop on that on Friday about AB 1900. So most of the biogas on the transportation is going to what we call tethered fleets, so these are primarily refuse truck fleets associated with a landfill facility where they're taking the landfill gas and cleaning it up, or taking the MSW organic feedstock, running that through a digester, and then putting it through an RNG station into a truck fleet. In my view, there is a very very strong future market potential because biogas has very very low carbon intensity values. Currently, there are about 11 to 13 grams, so again that's 90 percent below the baseline for diesel, and there's a new product coming up that will actually have a negative carbon number, and that's the high solids anaerobic digestion of organics. So more mature carbon markets, resolution of the gas quality issues through AB 1900, should help to alleviate some of these issues. So we're currently funding nine commercial plants.

To see how these markets might evolve, again on the truck side, we have about a million trucks in the fleet, they use a relatively small amount of fuel and generate a disproportionate amount of emissions and carbon. There is a pathway going forward which would be natural gas, which is very very cheap and a lot of truck fleets are switching over to that right now, so a combination of low NO_x engines, and increased market penetration of natural gas mixed with biogas has the potential to meet carbon and criteria emissions targets going forward. And I've got a few more stats on that, on the transition. If you go to Clean Energy's website, they're the premier natural gas retailer here in California, they now have a new division with RNG and they're offering what they call R20 and R10 RNG projects on the market, so it'll be interesting to see how that gets picked up.

The other big emerging market here is as a feedstock for renewable hydrogen. Many academic and agency modelers looking ahead to 2040 and 2050 think that hydrogen will be a major player in California and the rest of the country. By law, one-third of all hydrogen has to be a renewable and that means that there's going to be an increasing demand for biogas as a feedstock.

Lastly, as a process fuel replacement for biorefineries, and we've got a couple of our ethanol biorefineries here in California already looking at this transition, if you substitute biogas for natural gas, you push down the carbon footprint pretty quickly.

And that's it. That's my snapshot and overview, and I don't know if you want to do any clarifying questions? I'll take clarifying questions. If you've got kind of substantive questions, let's save them for the panel because that's what they're here to do. Thank you.

MR. KINNEY: Good morning. My name is Bill Kinney, I'm with the Emerging Fuels and Technology Office here at the Energy Commission. I just wanted to do a quick introduction of our panelists this morning. On my immediate left is Mike Waugh, he is the chief for the Transportation Fuels Branch at the California Air Resources Board. Nathan Parker is a Post-Doc at the Institution for Transportation Studies at

University of California at Davis. Mary Solecki is the Clean Fuels Program Director at Environmental Entrepreneurs, or sometimes known as E2. And finally, I have Paul -- sorry, I just lost that one --

MS. SALAZAR: Harris.

MR. KINNEY: -- Harris, excuse me, and he's a Chief Scientist at Novozymes. So without any further ado, Mike.

MR. WAUGH: Thank you, Bill. Thank you, Jim. It's a pleasure to be here early Monday morning, thank you for that.

MR. KINNEY: Yeah.

MR. WAUGH: So I would like to talk a little bit about what I see as the opportunities and the challenges for Biomass-to-Biofuel in California.

First I'd like to talk about the opportunities. And I think Jim had mentioned what is I think the best opportunity here in California, what provides the most incentive, and that is the Low Carbon Fuel Standard. The Low Carbon Fuel Standard is a performance-based standard, it's fuel-neutral, it doesn't proscribe what kind of low carbon fuels can be used or must be used for compliance, yet is a key driving force, I think, for biomass utilization mainly because, as Jim had alluded to and shown some numbers about how low the carbon intensity is of some of the biofuel -- or the biomass -- fuel pathways.

Briefly, let me talk about the LCFS. As Jim's slide said, the key objective is reduced carbon intensity transportation fuels by 10 percent by 2020, and that will achieve about 15 million metric tons of CO_2 or GHG emission reductions by 2020. And it's part of AB 32. It's about 10 percent -- it represents about 10 percent of the GHG emission reductions necessary to meet the 2020 goal of getting back to 1990 GHG emission levels.

The other thing that a lot of people don't realize perhaps is that one of the other key objectives of the LCFS is to transform the state's fuel supply, reducing obviously GHG emissions, but also enhancing energy independence. So in terms of the transportation fuel portfolio, the LCFS really drives more of a broader portfolio of transportation fuels.

Essentially the LCFS has annual carbon

intensity standards for gasoline and diesel and the fuels that replace it, and carbon intensity is a measure of the GHG emissions associated with the production and use of the fuel, and the unit is really grams of CO_2 equivalent per megajoule. Those who aren't familiar with what a megajoule is, it's a little less than 1,000 Btus, if you're more familiar with Btus. And the carbon intensity is based on a complete lifecycle analysis, and I'll show several examples here in a minute.

As far as the LCFS goes, who are the regulated parties? Well, anybody that really puts transportation fuel into the market is a regulated party. We're looking at mostly, you know, CARBOB, you know, gasoline diesel is the vast majority of it. But there are some fuels that already meet the 2020 CI goal, and they're exempt from the program if they can opt in to generate credits. These include electricity, hydrogen, natural gas, and biogas. And, in fact, electricity -- the utilities have opted in with electricity and natural gas, and I think Jim had mentioned clean energy, and they're a big provider of natural gas to transportation fuel, too. These credits can be bought and sold by regulated parties, and I'll show you where we are with that in just a minute.

Here's an example of a lifecycle of CARBOB. First of all, you've got the production from the oil well and this is an average of 11 grams per megajoule, it can be quite high. Some of the higher CI production of crude could include tar sands or a lot of thermally enhanced oil recovery steam injection, excessive flaring, so you have that on the one hand, and then you have conventional production on the other hand. I always say that the lowest CI oil production is probably what I call the Jed Clampett of oil production where you're shooting at some food and then up from the ground comes a bubbling crude, so that would be on one hand, and the other hand would be something like tar sands.

Then you have to get the oil to the refinery and you refine it, and then you get the CARBOB to the vehicle, and then you have tailpipe emissions. And I would say, obviously here about three-quarters of the lifecycle for CARBOB comes out of the tailpipe. So if you have 99 grams per megajoule total, about three-quarters of that is the CO_2 coming from the tailpipe. This is a little bit more complicated, but here you have growing and harvesting of corn, that's 36 grams, about 30 of that has to do with Ag chemicals, most of that fertilizer, most of that the production of the fertilizer; so you have 36 grams per megajoule from corn production, then you get the corn to the biorefinery, there's a wide range of carbon intensities here on the biorefinery, and that is a function of what the fuel may be; on the low end, you can have biomass as a fuel, on the high end you have coal. There are also differences in the efficiency with regard to the biorefineries, there's a wide spread there in terms of how much energy is required to make the ethanol. Then you get the ethanol to the vehicles, blended with CARBOB and gasoline, and then the tailpipe emissions, so zero and that's because the emissions are offset by the sequestration of the CO_2 from the corn itself; so, whereas before CARBOB was 75 percent of that lifecycle, here the tailpipe emissions are considered zero.

There are a couple other pieces here, one is called Land Use Change. This is considered a real phenomenon. I think there's consensus on that, the question is what that number is. Ultimately what this says is that, when you divert a crop-based feedstock from, say, food or livestock feed, or something like that in this particular case, and put it into ethanol, there is an increased demand, therefore, for corn and the price of corn goes up, and therefore farmers plant more corn and they displace some other crop, and eventually someone puts into production land that has been fallow. And when you plow the land, when you burn off the vegetation, or cut down trees, or whatever, and you plow up the land, there is a carbon emission associated with that, so that's what Land Use Change is. Like I said, the question is what is that number and we're working with several universities to refine that number as best we can.

The other square here is Co-products, and I think Jim had mentioned the distiller's grains, and so what happens after you make the corn ethanol in this particular case you end up with distillers grains which goes into livestock feed. So there's a credit there because there's less corn that has to be grown because you do have a co-product. And there are several co-products available for several biofuels, for example, glycerin is a by-product of biodiesel, and so this is an example of a full lifecycle for a corn ethanol.

Here is the lifecycle for cellulosic ethanol where you have forced waste collection. This is from waste forest products. So it takes some energy to collect the forest waste. You can see there are no land use change impacts, so that's zero, and then you get the wood chips to the biorefinery -- a pretty energy intensive process to make cellulosic ethanol. At the same time, you can take the lignin and burn it to provide your energy, so it is 136 grams to make the ethanol, but you have a credit of 130 grams per megajoule because you're using the same material for your energy. Then, you of course get the ethanol just like corn ethanol, the blend of CARBOB, get it to the vehicle, and the emissions are all set. You can see the cellulosic ethanol from waste forest products is very low, 22 grams per megajoule, and compare that to corn ethanol at 73-121, or CARBOB, 99.

So when I say that we're fuel neutral

with LCF, that's true, but the lower the CI, the better, and the better products demand a premium in the marketplace.

I think lifecycle analysis can be complex, it is complex, but in terms of compliance with the LCFS, I think it's pretty straightforward. Essentially, if you put a fuel or a blend stock into the market that is above the applicable standard for that year, it's going to generate a deficit, and if you put a fuel or a blend stock into the market that has a carbon intensity less than the standard, you're going to generate a credit, and ultimately at the end of the calendar year, which is the compliance year, you hope to have enough credits to offset your deficits.

To give you an example of some of the CIs, I've put the red ones that generate deficits, and the green ones generate credits. So gasoline and diesel will always generate deficits because those were what the standards were based on in terms of baseline; corn ethanol, as I showed you, has a wide range, some would generate credits and some would generate deficits; sugarcane ethanol generates credits;

and here again is cellulosic ethanol from forest waste. You can see that 22 is quite low, therefore I think the LCFS provides a value for cellulosic ethanol, and like I said, even though we're fuel neutral, this I think is a driver for additional use of biomass. Biodiesel has a wide range, from 4-83, 4 is corn oil, 83 is soy. Methane, which includes natural gas, Jim mentioned the negative CI for anaerobic digester. The reason this is negative is because there are methane emissions avoided at the landfill, so when you divert material from the landfill into an anaerobic digester, you get credit for methane emissions avoided at the landfill. So, again, this would be a fuel lifecycle that we could show another graph. In fact, there is, I think, something like 170 different fuel pathways, so I showed you three at this point. Most of them are variations on a theme, but nevertheless, we have a lot of fuel pathways and more coming in. I have a whole section that does nothing but look at fuel pathways. And electricity, of course, is low. The reason electricity is low is because it takes into account the efficiency of the electric motor versus an IC engine.

This supposedly would show the challenges, that's why my slide looks like -- but there will be challenges and here they are, no, I don't know what that -- where was that slide? Oh, that was an important slide that we didn't see, but moving along, I believe my handout hopefully shows it, though?

MR. KINNEY: Yeah, except I don't think we got the handouts, did we?

MR. WAUGH: Yeah.

MR. KINNEY: Oh, we did? Okay, all right, great.

MR. WAUGH: So anyways, what this mystery slide was showing was a bar charge showing the credits and deficits through the different quarters through 2011 and 2012, and what this slide shows here is that there are more credits being generated than deficits right now. So the regulated parties are over-complying with the LCFS, they're generating more credits than deficits, they're putting more blend stocks and fuels into the market that are below the applicable standard, and therefore generate more credits. In fact, they're something like 1.35 million metric tons of excess credit.

Source for the credits? Most of it is from lower CI ethanol. Like I said, if it's less than a standard and generates credit, we get about 10 percent from natural gas, eight percent from biodiesel, two percent from renewable diesel, electricity is in there, but it's a fraction of one percent at this point, but we certainly expect that to increase. As I said before, credits can be bought and sold. There's only one credit transaction in 2011, but through the first quarter of 2013, 79 transactions have occurred. The price range is anywhere between $10.00 and $47.00 per metric ton. We've seen, I guess in 2011 and 2012, it's like $10.00, and now it's gone up to between $40.00 and $50.00 per metric ton. Trade volumes can be as low as 13 metric tons all the way up to over 47,000 credits in one trade. So we're getting a more robust trading market, and I think that's because the standard is getting more and more restrictive. As I showed before, the LCFS -- the goal is to get 10 percent carbon intensity reduction by 2020, that's not a linear curve, it is back-loaded, the first five percent is achieved in seven years, and the last five percent in the last three years, so I think as the LCFS becomes more stringent, the price of credits will go up, and therefore the driving force for lower CI biofuels will also increase. And that's again why I think the LCFS is in a sense, you know, production of low CI biofuels, for example, from biomass.

The challenges, I've just got one slide on challenges here. I think challenges for biomass-based fuels -- financing -- I think we've all known that there was a recession and financing is tighter than it was. We're talking about pretty expensive processes, and so when you decide to invest a quarter of a billion, half a billion dollars into a plant, you know, that financing is a big part. The other is that you need a steady long term feedstock supply, for example, forest thinning projects probably will not give you a 20-year steady supply of wood chips from the forest, so if in fact you're going to put your plant down and use forest waste as a feedstock, you need a 20-year steady supply, so the occasional forest thinning project is not going to get you that.

So I think, much like what we see with

biodiesel and even renewable diesel, I think there is going to be multiple sources of feedstocks. So, for example, if you're using biomass, you may use Ag waste, forest waste, municipal solid waste, and so we think that there's going to be required multiple sources of feedstocks. Also, if you're going to go energy crops, you know, like switchgrass, or miscanthus, or something, the question is where to grow them. As I said before, with the crop-based feedstocks there's a Land Use Change value that is associated with that. And so if you grow some of these energy crops, what are you not growing instead? And you have again a displacement of certain crops so that I think that's a challenge.

Infrastructure is a challenge. I think we all know that there is a lack of infrastructure right now with biodiesel blending, but the infrastructure, whether it is natural gas or hydrogen that I think is a challenge.

And finally, permitting. For example, if you're going to use municipal solid waste as a fuel or as a feedstock, then you're going to want to build your plant pretty close to large landfills that meets in the urban areas, and there's always the issue, I think, of getting permits in those areas.

So I guess to sum up, I think the Low Carbon Fuel Standard is a perfect incentive for increased use of biomass because of the low Carbon Intensity. I think there are some challenges ahead. And if you want more information on the LCFS, here is the URL for the LCFS. Thank you.

MR. KINNEY: Thank, Mike. Our second speaker is Nathan Parker from U.C. Davis. It's all yours.

MR. PARKER: Thank you. So I'm Nathan Parker from U.C. Davis. I've been studying biofuels for a little while now for the State of California. And so I want to kind of go through some things about kind of where I think California could go with biofuels and where we are now, and then kind of get into a specific challenge for these cellulosic type biofuels. It's not just specific to cellulosic biofuels, but it is a great deal more problematic for them.

So California -- this slide is borrowed from Steve Kaffka, California Biomass Collaborative. The point is that the biomass resources in California are fairly large and very diverse, so there's whole lots of different types of biomass that are in California and they're located across the state in different locations.

This is a different version of the slide that Jim showed summing up the different biomass residues and what their fuel potential is. This is also stolen from Steve Kaffka, or borrowed from Steve Kaffka -- he gave me permission. But the point I want to make with this slide is that a lot of -- there's a diverse set of resources, but a significant quantity of these resources are lignocellulosic in nature, so they require these technologies that have yet to be fully commercialized. Oh, you can see what I'm pointing at -- fats, oils and greases, this is where you can get 56 million gallons a year from the waste fats and greases that are biodiesel feedstocks, or the renewable diesel feedstocks, so this is not going to solve our problems for needing large scale -- they'll be low CI, but they won't solve the quantity needs. There are also some gaseous resources, but I'm going to focus on the cellulosic of MSW, forest residues, and the Ag residues that are cellulosic, that make up the majority of this resource. So that's what I'm focusing on, but I also wanted to say that that's not all the possibilities, there's a potential to California of the grow crops that are more traditional crops, not the things that are usually talked about on a national level about what energy crops are, but, say, canola, sweet sorghum, sugar beets, safflower, Bermudagrass, and there's been some studies done at U.C. Davis that show that you could make enough to get a few biorefineries in California off of these feedstocks, and they're not going to take over agriculture and be a large resource for biofuels in the state, but they could provide something.

So if we're looking at the lignocellulosic biomass, they're new off-the-shelf technologies that we can utilize as this resource to make liquid fuels, so there's just a whole suite of technologies that may become commercially viable and they need to get there. The question is, how do they get there? So here's a graphic showing from, what I could glean from literature and press releases, where the capital costs are on biochemical ethanol, thermochemical ethanol, and pyrolysis bio-oil, and so these are all technologies that use lignocellulosic resources to produce liquid fuels. And in comparison, what we base most of our policy analysis on are these kinds of academic studies from NREL, National Renewable Energy Lab of what the costs will be once we know what we're doing with these technologies.

And this is comparing what the academics would say you will get compared to what the companies are releasing as to what they are spending. So there's definitely some learning that needs to happen to reduce these costs and to scale up to larger scales.

This is kind of to Jim's point that we've had -- that these cellulosic resources are the next thing coming in the future and they have been for a long time. This is not to be unexpected that we have these cost estimates and it takes a while to get there and, as we get closer to commercialization, we figure out they're going to cost more than we expected with our initial estimates. And if they cost more, it becomes harder to do them.

So this is an illustrative example of a

cost path. This is for SDR technology, so not very analogous, but it gives the idea of what's happening. And this is a technology that was pushed by regulation, so it's kind of similar in frame. But the costs go up as they get closer to commercialization and the first costs are very high, and eventually, 20 years later, and a lot of plants built, they reach the cost prices for what the technology assessments were when they started trying to push this technology.

So this is kind of an example of what you're working through, so I've done some work trying to look at, for biofuels what would that look like and how much you'd have to spend in order to get biofuels to the point where they're competitive with gasoline, cellulosic biofuels. And I'm using a whole lot of different perimeters and, since I don't know the answer about what things cost right now compared to what and how fast you will learn, there's a whole lot of uncertainty here. But an estimate from, if you were to start building cellulosic biofuels and build them out as they are projected for the next four to five years, and then pick up the pace, the corn ethanol build-up, that's kind of giving the time trajectory, and that the initial costs are one and a half to three times what the technology assessments were, and then learning rates are varying, kind of similar to corn ethanol and sugarcane ethanol.

Then you have this kind of big hump to get over and it's a long hump to get over for buying down the cost of getting these fuels into competitiveness. So this is where these regulations from the Low Carbon Fuel Standard and federally, the RFS, come into play to provide incentives to overcome this barrier. But if you were just a pure investor and you believe my cost values, then this is not a very pretty picture that it takes 15 years before you start having positive cash flows. If you get subsidies or LCFS credits, or written values, then you can switch this over and make it better and get a much better picture, and then kind of -- I said there are a lot of different perimeters that go into this, but the major one is the price of oil. To get competitive with oil, you have to beat oil, and the oil price is highly uncertain. So if you have a low oil price as the Energy Information Administrative projected versus a high oil price, if you have a low oil price you never get competitive. If you have a high oil price, you're competitive quickly, and it doesn't cost you much.

So this is kind of a summary of looking at all the different perimeters and values I looked at and what the buy-down cost is, so you have somewhere between $2 and $70 billion that you have to get into this, and this is a national study, national level, that California doesn't have to do this all by their selves, but it's also not that huge of a number. But you also have these cases, potential cases, where you're never competitive, and therefore it's risky.

So the conclusion from this analysis, the largest potential primary source for biofuels in California is these lignocellulosic resources. Buy down costs for commercialization is on the orders of tens of billions of dollars, and break-even values could be very long term, there's a long term campaign.

I actually wanted to make a few comments, so this is just my presentation that I created; but I wanted to make a few little comments on things that I've heard so far because Jim and

Mike have teed up things pretty nicely for me. On the E85, the E85 market hasn't been taking off and I don't think this should be very surprising to anyone because E85 has been expensive relative to gasoline. And it's only recently that the written values and the LCFS values have gotten to a point to where they may actually -- where they could provide incentive for a fuel provider; they could bridge the gap to make E85 actually cheaper. And there's some movement in that direction from the industry, we'll see what happens, I'm not giving up on it completely yet.

And then on -- my talk is a little bit about financing and that the picture I paint is not very pretty for financing and convincing people to pay it, so this is only the technology uncertainty part of it, the technology learning that needs to happen. There's also, if you believe these numbers you need these policies in order to help you to turn a profit while you are learning, and so there's the question of regulatory duration, durability of regulation. And then Mike was going through these CI values and they're complicated, and how they are set. Most of the experts that I hang out with who work on these things are having trouble pinning down exact values, and so it's a complicated thing and therefore, from the outside looking in from an investor's perspective, it's going to -- it's going to be hard to say what you expect a new technology to produce unless it's already on the books, so that forest residue pathway is on the books and so you can peg that one and say, "Oh, well, if we use forest residue," so if we get more of these kind of example pathways that are fairly representative of what's coming in, then they'll provide some investment certainty for getting LCFS values. And then the feedstock question is also difficult that Mike pointed out. So there are some serious challenges in order to get this off the ground, and that's where I'll leave it.

MR. KINNEY: Thanks, Nathan. Next speaker is Mary Solecki with E2.

MS. SOLECKI: Hi. Thank you. Can you hear me all right? Loud enough? Okay. Thanks for inviting me here today, I appreciate it. I made a couple of changes to my slides that you'll see up here on the screen over the weekend versus what you'll see in your handouts, nothing huge, just trying to keep you on your toes, that's all. And I appreciate a lot of the things that Nathan talked about because I'm going to talk about the Catch 22 that exists in financing biofuel projects. And I've got some slightly different pieces that I'm looking at currently as far as the specific projects that are happening in the United States, and so I actually have a few slightly different conclusions from what Nathan has, but I don't think that his conclusions are wrong by any means, they're just different in the scope of what he's looked at versus what I'm looking at.

Anyhow, biofuels are unique in the sense that they require just a lot of money, they require a lot of money through the research and development phase and then, again, through the commercial build-out, and they are competing with a technology that already has 100 years in the market. I'm not going to spend a lot of time on this slide, but suffice it to say that there's normally a very standard financing order of operations in the world, and biofuels are not necessarily going through the normal funding stages and strategies, in some ways they're jumping from stage 3 to stage 5, back to 4. And there are some very specific reasons for that which I will get into.

But normally you start by gaining your equity financing and going into debt in your later stages. And just quickly, the difference between equity versus status -- I'm not going to do a whole finance course on you here, it is Monday morning -- but equity is essentially investment that is ownership in your company and it's a really expensive way to finance a project because these are people that are investing in your company that see the value in your technology, and they may get nothing back in return, but really they're hoping they're going to get a lot back which is lots of future profits.

And you only want to delve out so much equity ownership in your company through those early stages because you don't want to scale up and find that you've actually completely financed all of the ownership out on your company and you no longer own anything. So when early on only equity is available, and this is typically a higher risk, and it's higher risk because, like I said, you're either getting nothing or you're potentially getting some future profits back, and equity takes the form of venture capital, strategic or corporate investments in the public markets.

With debt, there's no ownership and it is lower returns, but it's a fixed rate and that's just repaid with the interest. It is lower risk in the sense that you always pay your debt first, and you pay equity later if you have anything left over. And so a person that is making a debt financing agreement has more upfront assurance that they will receive their money back sooner. It requires cash flows for a banker to give you money, they want to see that you have a positive cash flow, and this is where biofuels start to really hit the Catch 22, and we'll talk a little bit more about that. And then banks and government agencies are typically the financiers of debt; it can sometimes be other corporate interests, companies that want to loan you money and receive their own money back with interest, but it's typically from banks and corporate agencies, or government agencies. And I should mention that -- we'll get into the public financing here in a moment and where things like AB 118 come in.

So the funding cycle starts out with venture capital providing the smallest amounts, and I've got some numbers here. I pulled the $13 billion in the first quarter of this year versus $11 billion in the first quarter of last year. Some of you might have heard that clean tech investment is down, and that is true, but this number -- this is from CleanTech Group, first of all, this number doesn't necessarily -- when they say clean tech, I don't think that they are looking at bio chemicals, and financing bio chemicals is way up, and that is a way that biofuel companies are trying to show some early cash flows so that they can later finance the fuels.

Venture capital feeds the early stage ventures in exchange for ownership and the high returns are in exchange for the high risk that these people are taking by giving you the money, and this typically goes into a pilot or demonstration-based project, so a biofuel company can be getting this for their research and development, for their first financing into a pilot facility, or even a demonstration phase facility, but a lot of times those demonstration phase facilities are a little bit more money than even a venture capital, a VC would provide.

So that takes them to the next stage which is Strategic Investments. It's the next round of the bigger pockets, and that's where it's typically from another company that might have some vested interest in seeing that your technology succeeds, or they might see, for example, if Novozymes were to provide a strategic investment to a biofuel company, it's with the understanding that they will be later using some of the Novozymes technology, and so they're essentially helping fund a future customer for their product. It is uniquely defined by every transaction, I can't make too many broad sweeps about what strategic investments look like. Sometimes it's an exchange for ownership, sometimes it's a set amount of payback or cash flows, but it can help finance your demonstration or your commercial phase project. I've got another example down there where this sort of arrangement resulted in a commercial project, which was when Tyson Foods went into a joint venture with Syntroleum, so Tyson is providing the feedstock, which is the animal fat, and then Syntroleum is getting the output, and so that there's something in there for both of them. So that's how they found their money.

And then finally into the public offerings where this is almost the largest pools of money you can find, at least on the equity stage, and typically you want to do this soon after you're turning a profit. Now, biofuel companies aren't necessarily doing this because they're in this Catch 22, they need the cash flows in order to get the debt, but they can't get the debt without getting the cash flows. And they're stuck in this vicious cycle and so they're going to the public markets a little bit earlier than the normal stage of financing, and so in 2011, I believe it was, there were many many biofuel applications to go public and what happened was they all went public, or many of them -- about five of them went public in one year. And then when none of them were turning a profit because they did not yet have a commercial facility, their stock price dropped way down and that made the public markets lose all appetite to see anymore biofuel companies go public. And so it created an application glut, there were many projects that just sat with their public filings that they never actually took it public, and they started seeking other sources of financing. And a lot of times these other sources became the public financing, which we'll talk a little bit about that.

And at the commercial phase, the cost figure that I've been looking at, and this is from the SEC filings, from the 10K and the 10Qs, I've been looking at $10.00 a gallon more or less is what a lot of them seem to be trying to target with their capital expenditures, and that means if they're building a facility of 100 million gallons, then they're looking at, oh, gosh, Monday morning brain, they're looking at ten -- why am I -- "ten hundred million" -- yeah -- so they're looking at a lot of money in that first phase, or that bulk amount. And that's a large amount of money. You can sometimes get that much money from a public offering and sometimes you can't. And we'll go into some specific examples here in a minute. And then ideally, after there is -- after they have these large amounts of money coming in from their public offerings, they might have been able to finance their facility, perhaps they haven't, and so if that's not enough, that's when they start looking at debt. And the debt equity, with a very capital intensive industry, like a biorefinery where there is so much infrastructure needed, they're typically looking at about $2.00 of debt for every $1.00 of equity on their books. And like I mentioned, banks or sometimes other companies are providing that and the current market rate, at least what I'm seeing from the SEC filings, is about 8 percent that companies are receiving on these loans. And they can be difficult to access, especially with new technologies. I like to joke that everybody likes to be the first person to invest in a second facility, and nobody wants to be the first to invest in a first facility, that's the problem, and the lower a return is necessary for large sums. And so this is a preferable form of financing for a lot of companies because it's just a less expensive type of financing if they're only having to pay back orders of eight percent as opposed to the equity, where that can be 20 percent or higher returns.

And then because of these Catch 22s I've been talking about, that's why the public financing is such a critical part of the biofuels scale-up and investment cycles here, because they're requiring some public grants to help them with these R&D costs, and to provide them with some capital that isn't necessarily as expensive as the equity, and that's through the grants like AB 118 or a loan guarantee. A loan guarantee just assures that the debt will be paid with the borrower defaults.

Off-take agreements are also really helpful. If the company can show that they have a guaranteed market when they produce their product, then they have access to debt financing and they can take that to the bank and show them, "Look, I know I can sell my product at this price for this many years, so give me this kind of a financing rate," that that's very helpful to them. And that can come both from a bank, it can also come from a public entity, for example, if the State of California were to guarantee that they would purchase some quantity of biofuel for a number of years. So I'm going to look at a few different examples here, including Solazyme and

KiOR, and LanzaTech, and just talk about the different ways these companies have scaled up and how they've walked to this spidery web. Solazyme received venture capital at least starting in 2003, potentially a little bit before then, and they can be continuing to receive venture capital all the way through as they're looking at new technologies and doing additional research and development. And then, for their demonstration phase facility in Peoria, Illinois, they received a DOE grant, and that was for $22 million for a two million liter facility. And then they went public in June 2011 at $201 million and, like I mentioned, this is one of the companies that went public without actually having a commercial-scale product, so they weren't yet turning a profit. And to try and help themselves there, they're looking very heavily at the biochemical companies like Amyris and Solazyme in California, are going with this route because the biochemicals fetch a much higher revenue, and it can help provide the financing that they need to invest in these hugely capitally expensive projects like the commercial facilities. Then the CEC has agreed to -- even though Solazyme is a little bit farther along in their lifecycle, CEC has recently granted $1.5 million and this is back into R&D for their pilot facility, so they're going to continue to look at some new technologies there. And I think that the partnerships that Solazyme procured for their plant financing are pretty interesting. I think it's pronounced Bungee (ph) if anybody -- correct me if I'm wrong there -- but Bunge is a Brazilian based company and, through Solazyme's partnership with them, they were actually able to approach the Brazilian development bank for a really low interest loan for a facility down there. And Solazyme had to provide some of that money upfront with cash. Presumably they got that cash through their public offering, or through the small amounts of revenue that they're receiving from selling their biochemicals, and now they're able to receive the rest of the money they need to build that facility from the bank. And they're also renting a facility in Iowa, and that's another interesting way to start to produce your product at a commercial level, they're not actually needing any capital expenditures for that, they're just renting the facility and providing some stock to Archer Daniels Midland in exchange for that. And that's a 20,000 metric ton facility. So, again, this isn't necessarily a normal lifecycle of financing into a company, but this is how they're navigating these things.

KeOR -- and I think that KeOR has an interesting technology, especially for California to consider because they are using woody biomass and especially in the northern half of the state, that would help meet the goals that Rachel was mentioning in the community-scale biomass facilities for the Bioenergy Action Plan. And KeOR, this information I've gotten from both their SEC filings and from conversations with Vinod Khosla. And their public offering was also in June of 2011 at $150 million, and their first facility that's in Mississippi was funded by cash from that public offering and from an interest-free loan from the Mississippi Development Authority, again, the strong role that public financing is playing in this. And that was a $200 million facility with 11 million gallons of capacity. So with RINs, they're able to pay that back in just three years and, without, the payback is eight to 10 years, which still isn't a bad payback time period at all. And the next plan is for a facility of 450 million gallons, and then they're working on the third. So the cash flow from these first three -- or from the first two is going to be sufficient to fund any of the facilities thereafter, and so this is another slightly differently take on a normal investment flow.

And finally, we'll take a peek at what LanzaTech is up to. They're currently hunting about $60 to $80 million in investments and it's my belief that they'll probably get this from strategic partnerships from other companies that want them to use their technologies or their products in some way, or it could even potentially come from, since they're using flue gas from coal facilities, they could even receive investment from coal facilities. So they are currently building a 10 and a 25 million gallon facility in China, and they have stated that they're going to wait for their facility to be operational until they go into their initial public offering, so hopefully that means that they're going to have a little bit of cash flow before going public, which means they might be able to fetch a higher price on that initial public offering and keep their stock at a more stable price, as compared to the massive downturn that you've seen with some of the others. They've purchased their Range Fuels facility in Georgia in January of 2012, and they have a swath of different public grants and loans and subsidies provided by many different U.S. and Chinese-based entities. So that's just a brief look at what three different companies are doing. Every company is unique in this area, but suffice it to say that it's not necessarily -- it's been interesting to see how they are walking these fine lines and how critical this public financing aspect is to helping them compete within an existing technology.

My last comment on that is that the biofuel companies -- this is a broad generalization -- are looking at about $100 per barrel as the price at which they can be competitive with oil. Some of them claim they can be competitive even a little bit lower than that price, but $100 per barrel seems like that is a reasonable price given where the price of oil is going in the future, considering that even the tar sands projects require oil to be $80 per barrel for those to be competitive. So that's all I have. Thanks.

MR. KINNEY: Thanks, Mary. And our last speaker is Paul Harris from Novozymes.

MR. HARRIS: Yes, and thank you for the invitation. So I'm going to talk a little bit about the biochemical conversion platform. These are the topics I'm going to cover. And I'm a Staff Scientist at Novozymes and, as shown in the next slide here, we are the world's largest producer of industrial enzymes, so industrial enzymes are the enzymes that are made in ton quantities. They go into things like detergents to make your clothes clean. But for the last 13 years or so, I've been focused particularly on developing the enzymes for hydrolysis of cellulosic biomass, converting cellulosic biomass to simple sugars, in other words.

We have the largest market share in the industrial enzyme business, about 47 percent. And right now, in that second pie chart, you can see that we get about 32 percent of our revenue from what we call technical enzymes, and about half of that is actually from selling the enzymes that convert cornstarch to ethanol currently, so that's a big revenue stream for us. And naturally we want to maintain that revenue stream going into cellulosic ethanol.

So the biochemical platform very simply is converting a complex carbohydrate source, or even a simple carbohydrate source in this case, and sometimes using very expensive pretreatment technologies and relatively expensive enzymes to hydrolyze that material down to simple sugars. And we're very agnostic about what anybody does with those sugars. Those sugars can be, of course, taken through fermentation to produce ethanol, that is certainly technologically the simplest route to go, and the one that is the most mature, but people have taken other routes, as well, to use those simple sugars, fermentation with engineered microbes, and I'll give some examples of that, and Mary already has, and also heterotrophic algae, as Solazyme uses, to produce a variety of products. And these can be drop-in biofuels, diesel fuel, jet fuels, all kinds of products can be produced by these engineered microbes.

So I think the best evidence that progress has been made in the cellulosic ethanol field is that the industry is finally starting to emerge and commercial plants are being built, construction plans have been made, ground has been broken on many plants, and there is one plant currently operational, which I'll talk about in more detail.

And this is just an overview of the major projects that are going on in the world. I've left out some of the projects where they're producing biochemicals as opposed to ethanol as their end product, there are several of those in China which have already been fairly commercially successful.

So the one that I'm going to talk about primarily, well, let me just point out California because we have Canergy that is slated to go in operation in approximately 2016, and I'll talk about that in a little bit more detail. There's a great deal of activity in Brazil, and I'll also talk about that in more detail. And naturally, most of the activity in the United States is occurring in the Midwest where we have the corn stover available for the second generation ethanol plants that are planned and under construction there, such as the POET project in Iowa, which is already well underway.

So as Mary mentioned, Solazyme uses heterotrophic algae to produce oils from sugar and right now their sugar source is sugarcane or corn-based, but in theory they could use cellulosic sugar if they can overcome some problems with inhibitors in the sugar that's generated from cellulosic sources. And, as Mary indicated, they are currently concentrating on the high value low volume designer triglyceride market in an attempt to make money. The same is true with LS9 at Amyris using engineered microbes as opposed to microalgae and synthesizing a large range of chemicals that have the potential to produce fuels, but they've had scale-up difficulties, you might say, and so they are also focusing at this point typically on the lower volume, higher value markets. They also in theory could use cellulosic sugars as their source, although they can use a variety of other sugars, as well. Canergy is a very interesting company. They are in collaboration with Beta-Renewables that I'll talk about in the next couple of slides, plans to build a 25 million gallon per year cellulosic facility. They're slated to start construction in 2014, and their biomass source is going to be energy cane, so not a waste product, but an actual energy crop.

And so, in the interest of full disclosure, I do want to say that Novozymes does have a minority investment in Beta-Renewables, but that's not really why I'm showing this slide, I'm showing it because this is the first commercial cellulosic ethanol plant in existence, and it is currently operational. We just had some people from Davis visit the plant two weeks ago, and they could testify to the fact that it is producing at the rate of several million gallons of ethanol per year. Once they're in full operation, they'll be producing about 13 million gallons of ethanol and ultimately will scale-up to 20 million gallons of ethanol per year. This plant, as I say, the tanks here I'm showing with our logo on it are actually the enzyme storage tanks. It takes an enormous amount of enzyme to convert lignocellulosic materials to sugars, which are then being fermented to ethanol. And these are just the storage tanks in which they temporarily hold the enzyme they need, oh, probably in full operation they'll need a couple of truckloads of enzyme being delivered per day. They've already sold licenses for commercialization of their technology in Brazil and to Canergy, as well. This is another shot of the plant just to give you an idea of the scale of this operation. When they are in full operation, they're going to require five to six truckloads of biomass to be delivered per day, or per hour, I'm sorry, so about one truckload every 10 minutes to produce those 20 million gallons of ethanol that they're talking about, and they have an enormous storage facility for holding the biomass temporarily.

Right now, the biomass source primarily is Wheat Straw, but ultimately they want to use Arundo donax, the giant cane as an energy source, along with additional agricultural resources that are available in Northern Italy.

So the relevance of this to California is that the same technology is going to be used to build the Canergy Refinery in Imperial Valley and it is -- well, I won't say yet that it is a proven technology, but they are actually producing ethanol and they are selling that ethanol to Shell currently; I don't know what the price of it is, and they probably wouldn't want me to tell you if I did know.

Also, one of the near future feedstocks in Crescentino will be Arundo donax, as I mentioned, a plant that grows extremely well in California, in fact, too well, it's considered a pest, a weed pest, but it does have very minimal tillage, fertilizer and pesticide requirements and it's quite drought resistant. Although it grows in typically wet environments, it's quite resistant to drought conditions.

Also, Northern Italy is a lot like Northern California, it's the largest rice-growing region in Europe, and rice draw is slated to be a future source of biomass at Crescentino. And I think rice straw in Northern California good potentially produce something on the order of 100 million gallons of ethanol per year if it were fully utilized.

Another company that I want to mention, and we don't have any investment in this company, is Fiberight, I just like the company, we've been working with them now for several years, they are in the business of converting Municipal Solid Waste to biofuels and Municipal Solid Waste has the potential of producing about 5 billion gallons of fuel, and Fiberight has an operational plant, and they have proven the technology to be economical at that particular scale, and right now they are planning to build a commercial facility in Iowa with a $25 million loan guarantee from the U.S.D.A. and a total $50 million equity investment. And the expected capacity of this plant is not huge, it's six million gallons per year, but anything is better than nothing. And if successful with this commercial plant, they plan to target expansion to communities larger than 100,000 populations, particularly where they have landfill problems, or high cost of Municipal Solid Waste disposal. About 25 percent of the Municipal Solid Waste can actually be used to produce cellulosic sugars, and it's actually, from a capex perspective, it's one of the lower -- on the lower end, and also the feedstock itself, the cost of that is on the lower end.

So the barriers I see to commercialization in general and also in

California, of course, is the blend wall. We all know that the EPA recently raised the blend wall from E10 to E15, but adoption of E15 has been extremely slow due to concerns, whether real or imagined, and I'll leave that to others, about potential vehicle damage and the effects on small engines, and also given the recent decrease in overall gasoline consumption in this country, corn ethanol could actually meet the E10 blend requirement currently, so there isn't a lot of room for cellulosic ethanol to go into the fuel supply except as part of the RFS.

Now, that blend wall could be exceeded by using E85. As others have indicated, E85 is still somewhat expensive, but potentially competitive, particularly if you use a vehicle that has a high compression ratio engine, or a variable compression ratio engine that can make use of the high octane rating of E85 to be much more efficient in its energy conversion efficiency. But, of course, flex fuel vehicles are only about four and a half percent of the light vehicle fleet in this country currently. I think somebody said there were about 400,000 of them in California, so not very many cars can actually use E85.

There's also a loophole in the RFS, well, some people call it a loophole. So there's a requirement for blending advanced biofuels like cellulosic ethanol into the fuel supply, and that's going to be 2.75 billion gallons in 2013. But Brazilian sugarcane qualifies as an advanced biofuel, and legitimately so because it has lower carbon intensity, as we already heard. But ironically, this has led to the importation of Brazilian sugarcane ethanol into this country to the tune of about almost 500 million gallons last year in order to meet this RFS Standard, despite the fact that there is an abundance of U.S. produced and cheaper domestic corn ethanol. And, of course, this leaves little room for cellulosic ethanol, as well, and difficult at this point for cellulosic ethanol to compete on a cost basis with Brazilian sugarcane ethanol and to fulfill this advanced fuel requirement of the RFS.

We've already heard about the high capex for cellulosic biofuels, I won't argue what the real numbers are, I don't really know what the real numbers are; I'll accept the experts' that it's probably at least $10.00 per gallon if not more. And much of this capex arises from the very expensive pre-treatment equipment that is required to treat the cellulosic material so that it then is enzyme digestible.

Wastewater treatment is also a big part of the capital expenditure and also the boiler for energy production, so these plants are self-sufficient with respect to energy production, they do of course gain a credit if they want to sell some of that energy, produce electricity, and sell some of that back to the grid and they will typically produce excess energy.

And then feedstock supply and logistics, that has already, I think, been covered. The pretreatment expense, as I indicated -- pre-treatment technologies are constantly evolving and they are getting cheaper over time. The Proeso technology that Beta-Renewables uses is one of the cheaper in terms of capital expenditure, which is one of the reasons that that particular technology looks attractive. And enzyme costs, something dear to my own heart since I've been working for 10 years to lower that cost, great strides have been made. We've gone from a cost of about $5.00 per gallon of ethanol for enzyme cost, down to below $.50 per gallon of ethanol, so better than an order of magnitude reduction. And the next generation of enzymes is going to be even better. We'll ultimately get that cost down -- perhaps not to where we are with starch ethanol, which is more like $.05 to $.10 per gallon, but certainly below $.25.

Quickly, I just want -- and this is a way too wordy slide -- but I just want to highlight Brazil as the poster child for cellulosic ethanol, and I think we're going to see in the next five years cellulosic ethanol is going to take off in Brazil much more rapidly than it does in the United States or in Europe, and that's partly because they already have the infrastructure in place to support ethanol in their fuel supply, but also because of a lot of direct and indirect government incentives. And I want to point out, too, that the Gross Domestic Product in Brazil is roughly the same as California's, about $2 trillion. So they are able with their GDP to invest quite a bit of money in both first- and second-generation biofuels, and I've just highlighted some of the things that the Brazilian Government is doing both in the way of direct incentives, and you can go over these in detail yourself later, but also indirect incentives, and the industry itself is using a lot of its own funds and private banks are investing a lot of funds in Brazilian Ethanol, both more second generation than first generation at this point.

Just to highlight a few of the companies in Brazil that are major players and what they're doing right now, GraalBio has ssome ambitious plans for future expansion, but right now they're building a 12 million gallon per year plant; Beta-Renewables owns the Crescentino Plant, has a pipeline in Brazil that they are planning, it has yet to be under construction; Raizen -- and the "R" is pronounced like "H" in Portuguese, in case you're wondering -- has a very ambitious plan to build 10 cellulosic ethanol plants with a combined capacity of about 500 billion gallons over the next 10 years. And you can look at some of the others for yourself. Inbicon is actually a Danish company, as is Novozymes. And that was it for my presentation.

MR. KINNEY: Okay. I guess we've got a

couple of different things we can do here. How are we doing for time? We're okay? Okay. You want to just take a break yet or -- got time for a break? All right, let's do that. Let's take a five-minute break and we'll come back with questions and comments.

(Break at 10:45 a.m.)

(Reconvene at 11:03 a.m.)

MR. MARISCAL: All right, everybody, if we can have a seat we're going to get started.

MR. KINNEY: Okay, if we can get seated here, we'll try and -- okay, I'm just going to pose a couple of issues here and then maybe we can open it to the audience to raise questions and our panelists to respond. So a couple of things that came out and sort of impressed us in our AB 118 program is the importance of RIN values and the diesel substitute market, and perhaps now emerging in the gasoline substitute market. So, you know, I have sort of a general question about how those values impact availability of financing from various sources and then maybe for Mike, if you guys have done any of this, what sorts of values per ton for credit would generate significant impacts on per gallon operating costs, in other words, maybe $.25 up to maybe even $2.00 a gallon, and what sort of values per ton would achieve that, if you've done that work or not, maybe that's a question for the market to work itself out.

And then, I guess one of the issues that we keep hearing, biochems have a co-product and a cash flow enhancer, and to what extent is the attractiveness of high value biochems perhaps going to divert resources from biofuel production to biochem production because they're using the same feedstocks, but you're getting different products. So that's probably something from the Energy Commission's perspective as something that we ask, or think about. And I guess that's probably all I have at this point. Let's see, maybe we should open it up for the audience and online, and then we can circle back to those issues if we have time. So I guess we'll start here. Do we have anyone in the audience that wants to throw a question or -- please introduce yourself.

MR. EDGAR: Good morning. My name is Evan Edgar representing the California Refuse Recycling Coalition. We're the 100 private sector fleet out there throughout California, but who are the tethered fleets, whatever that means. But this is more of a question to Mr. McKinney over there. With regards to the NationStates stats, you have good numbers on gasoline and diesel, but I've got some numbers on what is a current CNG usage. On behalf of the California Refuse Recycling Council, we're transitioning our fleet from diesel to CNG, and then to renewable CNG. I've used CNG as a bridge fuel in order for our industry to -- we're already on our way, on the pathway with 15,000 heavy-duty fleet out there going towards CNG, we're co-locating our fleet not at landfills, I think that's the last place that our industry would want to put any anaerobic digestion facilities, we're not the landfill people. When you look at the recycling and the composters, when we look at making anaerobic digestion it's in-town, in-vessel, so we're co-locating anaerobic digestion facilities in-town next to our fleet where we're having fueling stations. When I testify in front of the California Air Resources Control Board with Mary Nichols on a cap-and-trade program to invest in this type of program, I talk about carbon negative fleets and she looks at me, "carbon negative fleets?" And I was glad today to see the Powerpoint presentation that recognizes dry anaerobic digestion as -15, so I've been promoting this to take this in-town, in-vessel, co-located anaerobic digestion for the 15,000 heavy-duty fleets in order to have a carbonated fleet. So I guess my question is, as part of your stats it would be nice to track CNG fuel usage, too, on a California basis as part of your database, and to recognize that to have a tethered fleet is okay, there's nothing wrong with having fleets not on a pipeline. I don't really -- I'm not a pipeline guy, we don't need to have pipelines as part of our anaerobic digestion industry. I represent a lot of emerging industry where we're in-town, in-vessel taking food waste and green waste, and we're co-locating them right out our yards so we can just take our biomethane, upgrade it, and put it into the fleet, so we don't need a pipeline in order to have this industry emerge. We're not the landfill people, so the California Refuse Recycling Counsel and the California Compost Coalition, who I represent, are looking forward to participating in this process and to say it's okay to have a tethered fleet off the pipeline, away from a landfill in-town, in-vessel. Thank you.

MR. KINNEY: Thank you. Did you want to say something, Jim?

MR. MCKINNEY: Yeah. I know this is an IEPR workshop, so let me premise this with the number I'm about to cite is from memory, it may be wrong, and we'll to -- so Tim Olson in our Transportation Energy Office will have statistics on that in his chapter of the IEPR report, but I want to say we're at about 15,000 natural gas trucks right now in California, Tim, yes? No? Something like that? Good. But, again, we'll have better data later this summer. And thank you for your comments.

MR. THEROUX: Good morning, folks. Excellent presentations and an amazing amount of material. My name is Michael Theroux, JDMT. First, probably the gnarliest piece, we see pretty clearly that the amount of potential feedstock in California that can be derived from Municipal Solid Waste is right up there with anything that we can get our hands on. We see in

Brazil that the breakpoint is that they already have the infrastructure. Well, of all of the kinds of sources of biomass materials or alternative fuels materials that we might be able to work with in California, certainly the place that we have the infrastructure is, again, with the Urban Waste Municipal Solid Waste. Why do we find such difficulty and such opposition to push that through?

Let me put my pointed little finger on one sore spot. The third bullet of the Bioenergy Action Plan asks, directs that we establish the proper standards for the front end processing and that includes for the urban wastes, as well. The PRC Section 40180 identifies what recycling is. Recycling isn't just picking the cans out of the waste, recycling is collect, sort, clean, pre-treat, reconstitute back to raw materials. So if those raw materials go into biofuels, then the end point of that recycling pathway is by law recycling, and we're making fuels out of that. There's a disconnect there. Right now there's a silly bill going through the Legislature that actually made it past the Assembly, 1126, that somehow or another wants to say, no, no, you can't do conversion within this context to pathways, it's different from reconstituting. So I would ask you to look at what is the terminology we're using for reconstituting feedstock, preprocessing feedstock, reprocessing feedstock, and conversion of feedstock, it's all the same thing. And we all have the same basic suite of tools that we're working with. Now, if you'll buy that, that means we have an over-abundance of potential alternative fuels coming out of the urban sector; we have the infrastructure par excellence for managing those fuels. And as Evan knows, it is a location fit to the community infrastructure where we can actually already implement community-scale conversion, or reprocessing, or reconstituting if that's the word you want to use. Now, I know we don't want to call biofuels creation recycling, but it's essentially the same pathway, it's the same kind of thing that we're doing. I'll leave that one alone for the moment.

Fortunately, after a massive struggle, the U.S. Forest Service has now a new Forest Planning Rule and in that rule and in the processes that are around it, they've broken the ground on 10-year long term contracts to provide forest-sourced biofuels outward. So we do have that structure, it has been implemented. The Four Forest Restoration Initiative and all of the Massey Forest in Eastern Arizona is implementing the first project along that line right now, and Concord Blue, which is a gasification biomass, is in the process of utilizing those fuels and that whole project development is moving forward. So we are seeing some action on the ground there after the Forest Service, after perhaps a good decade, has struggled with how to break loose longer term contracts. This used to be all three years maximum that we could get out of forest biomass materials.

The last point that I'd like to ask you to consider is that, in between the liquid fuels and the things that we do for turning directly into electricity, we have a new players and that's called torrefied wood, and it's rising very very rapidly on a global basis. It means you just densify the energy structure at 70 percent of the volume and 90 percent of the energy, while baking out some of the volatiles and using those to run the process. Why is that important? We have 27 small coal plants, trying to figure out how to get off of coal and onto biomass in California, some of them are making it, some of them aren't. The material, once it has densified that much, can be transported. And that is the key that we find so difficult in trying to utilize forest resources and rural resource that are biomass. So perhaps take a look at torrefaction as one more of the toolset that we have, that we can use for energy densification and consider that the solid fuel that it creates, these black little bio-coal, green coal, or however you want to call it, also has a place at this table. Thank you.

MR. KINNEY: Do we have any comments about that? If not, any other questions in this audience here? We have a blue card here to Mary Solecki from Elisa Brown. Let's see, I'm having trouble reading this -- oh, "In regards to an eight percent debt interest rate, you mention government loan guarantees, but these loan guarantees reduce the debt interest rate by how much?"

MS. SOLECKI: That is an easy answer: it depends. It can typically reduce it because there is a lower risk associated with the debt if it's got a low guarantee behind it, it can reduce the interest rate. The amount varies by project, by capital amount, you name it, and I'm not even going to venture about a percentage amount.

Paul, do you have any other comments on that? No.

MR. KINNEY: Okay, do we have any other comments? Another question from Le Noda to Mike Waugh; perhaps I should let you read this, Mike. "In the LCFS credits to date, are the debits for high carbon intensity crude oil in the balance?" is the way it's worded. "Since the HCIC deficit is not specifically identified, how much is it?"

MR. WAUGH: Yeah, I think I referred earlier to the crude oil CI when I showed the lifecycle slide and made the crack about Jed Clampett. The way the LCFS works with regard to crude oil right now is that we have what's called a California Average, that's what that 11 grams per megajoule was, and that's a 2010 average carbon intensity of the crudes that were supplied to the California refineries in 2010. And the way the California average works is that that crude slate CI will be recalculated in subsequent years and compared to the baseline. When you compare it to the baseline, if in fact the average crude mix for California refineries has a higher carbon intensity in 2010, then an incremental deficient will be applied industry-wide to the refiners.

So in terms of the LCFS credits to date, that was the slide that was the mystery slide, that would have shown the bar graph that it showed here, the deficits in here, the credits for each quarter; those credits do not take into account any incremental deficits that would be applied to having higher carbon intensity crude oils. So to answer the question that any impact from high carbon intensity crude oils has not been identified yet, we are looking at calculating 2012 crude slate compared to 2010, and we should have those results probably within the next month or so.

MR. MARISCAL: I'll go ahead and just mention something -- the slide that Mike Waugh is mentioning, there are hard copies on the back table. The file on our network drive is corrupted, so we will have to get a new version for the people on the Web and we'll post that probably tomorrow.

MR. WAUGH: There's probably a Windows 98 problem that the Energy Commission has, I think.

MR. KINNEY: I believe we have a lot of problems like that, at least my computer does every day, issues like that. Any other questions from the audience? Online? I'd like to circle back to Mary. Have you been able to sort of digest what impacts the Federal and State carbon credits might be having on the appetite for financing biofuels production?

MS. SOLECKI: Sure. The Federal -- the renewable identification number credits provided under the Renewable Fuel Standard, those are having a significant impact on investment into biofuels in the biorefineries, that is the main driver; because those are being incorporated at the investment stage when an investor is making a decision about a project, they're able to more or less calculate a worst case scenario RIN value into the future and take that into consideration with the price of the technology.

When it comes to LCFS credits, there is no minimum value for LCFS credits and, as a relatively new program, there's a little bit of political uncertainty behind it and E2 is working very hard to help remove that political uncertainty, I will state. And as far as the -- since there is no minimum value of the LCFS credits, that's really the key driver behind it. Investors zero out the value of LCFS credits, they apply no future value. And so, Mr. Waugh, we are trying to assert that a minimum LCFS credit value would help investments into biofuels as part of a cost containment mechanism if there was also a floor price that could provide some guaranteed future values and drive greater investments into biofuels. Thanks for setting me up on that one, Bill.

MR. KINNEY: Uh-huh.

MR. WAUGH: I would like to add that, for example, you know Paul mentioned that the National Bank for Economic and Social Development in Brazil is looking at the next generation biofuels; we've met with them a couple of times, they've come in to ask us in terms of the additional financial benefit through the LCFS, so just the fact that they've inquired, I think, is a good sign that people are wondering what added value there is with regard to the LCFS. In fact, I think there was a slide earlier talking about how much sugarcane ethanol is coming into the United States to get the RIN credits because they are at an advanced biofuel under the RFS program, the Federal program. Then the question is, is there additional value in California because of the LCFS? So I think a lot of the sugarcane ethanol is coming to the United States for the RIN credits and, in addition, we're seeing some of that come to California so they can get the RIN credits and the LCFS credits, as well. So we are seeing at least some inquiries and some behavior that would indicate that the LCFS does add value to the lower carbon intensity biofuels.

MR. KINNEY: So if you want to take on the general question of what sort of price signal you guys are hoping to get to drive the biofuels development?

MR. WAUGH: Well, there's no real single value. As I said before, the credit that's generated is relative to what the standard is for that year, so first of all one must determine what the energy content of the biofuel is in terms of megajoules per gallon, then figure out how many megajoules of fuel that you've brought in, at what carbon intensity is that fuel, what is that relative to the standard for that year, and then, finally, what is the price of credits. So I was scribbling down here and I said, well, with ethanol you're looking at about 81 megajoules per gallon, in 2014 the standard is 96.56, if you've got a 22 CI, which is what I presented up there for forest waste, then you would subtract 22 from 96.56, which is where you are relative to the standard. Then there's a million grams per metric ton, and if the price of the credits is $50.00 per metric ton, I penciled out here and, again, it's still Monday morning, but this example would show something like $.30 per gallon for the ethanol. But again, it depends on what your energy content is, where you are relative to the standard, and what the price of the credits are, so that would be a continuing type of calculation.

MR. KINNEY: That's informative, thanks, Mike. So does anybody want to take on the general question of are biochemicals an aid to getting biofuels production facilities built? Are they in some ways a diversion of resources from biofuels production to at least something of higher value --

MR. MARISCAL: I can make a comment on that.

MR. KINNEY: Okay.

MR. HARRIS: If you look at the petroleum industry, they don't just make fuel --

MR. KINNEY: Right.

MR. HARRIS: -- they make a lot of high value products. And, in fact, they use every drop of oil in that barrel, and much of it is to make high value, low volume products, and that's part of their economic model. And certainly if you look at the economic models for the future of biorefineries, they include as part of that economic model the production of high value, low volume chemicals. And because they are relatively low volume compared to fuels, they wouldn't really be sapping off a lot of the biomass resources to produce them, but they do add considerable value and allow those biorefineries to then sell the ethanol or whatever biofuel they're making at a lower price.

MR. KINNEY: Any other comments or questions? Tim.

MR. OLSEN: Tim Olsen, the California

Energy Commission, Transportation Energy Office. I want to go back on the RIN credit, LCFS credit. We heard on our -- we had a workshop on Friday, this last Friday on Biomethane. Developers there basically said difficulties in any of those credits and project financing that they're seeing is just year to year, that investors want some longer term kind of commitments. And my understanding is that RIN credits are year by year, it's not just a onetime thing, and it's continual as long as you're producing the fuel. And any ideas on how to turn that into contracts, or how -- first of all, do you agree with that comment that there's no way to turn it into a long term contract? And do you have any insights on that? And maybe, Mary and Paul, you have the experience in that area.

MS. SOLECKI: I'm not sure that I can, oh, 100 percent answer your question there, Tim. As far as the -- the RIN credits are being factored into the investments, so when investors are making the decision, I can't necessarily speak to exactly what value they're giving. I think it's an individual investor's assessment of the market and what future value they want to apply to RIN credits. But because it's a volumetric standard and not a performance-based, that that's a difference in how they're able to ascribe those future values, and that they view the LCFS credits as just potential upside. So it's not a perfect answer to your question at all, but maybe somebody else has some thoughts there?

MR. HARRIS: But do you think the value of the RIN credit, though, is predicated to some extent on the confidence they place and that RIN credit remaining in place for long periods of time.

MS. SOLECKI: Absolutely.

MR. HARRIS: So that affects the value. So if they had a high confidence that that credit would stay in place long term, it would be a more valuable --

MS. SOLECKI: Yes, absolutely. They're doing a risk assessment to the RIN credit prices and to the LCFS credit prices.

MR. HARRIS: So in either case, making that a more high confidence -- or having a higher confidence that that would exist in the future would increase the value of that.

MS. SOLECKI: Absolutely. And that's another thing that any advance biofuel producer will cite, that more regulatory certainty would be a huge driver for investment, that any political uncertainty that is put into the LCFS or the Renewable Fuel Standard is very very harmful to their potential investments.

MR. WAUGH: And I would just add that we're trying to provide that certainty with the LCFS. You know, there are a couple lawsuits that are in play right now with the LCFS. I think when they get resolved, you know, I think they will emerge with more certainty about the program and so we would -- personally, I would like to think that someone can take LCFS credit potential down to the bank and say, "This is part of the revenue stream," so we're striving for certainty with the LCFS as far as it being a program that's going to be here.

MR. OLSEN: Another related question regarding contracts, multi-year contracts. I didn't hear you mention much about fuel -- you mentioned off-taker agreements, but longer term contracts. As you probably know, with the biodiesel industry, that doesn't exist, it's pretty much a spot market, but it works, the market works. And we know with the corn ethanol producers in the state, switching to MILO, that they're signing three-year contracts for growers, fuel suppliers. So I guess, any ideas on -- what does that do? It seems like that would kind of help stabilize investments if you can get a lot of term contract on the fuel supply. But any ideas on how that would work, or just your experience with that?

MR. PARKER: So on the biodiesel side, part of the reason that it can be a spot market is it's less capital intensive. It's a feedstock intensive process. The cost is the feedstock and a small amount on the capital. So feedstock duration, the long term contracts with the feedstock is more important for these things that are very capital intensive.

MS. SOLECKI: The off-take agreements can be especially helpful for the drop-in fuels like renewable gasoline, renewable diesel, so those that are producing essentially a renewable crude oil, that could also be processed at a traditional refinery because, like Nathan said, it's not necessarily on the same -- it's a different capital infrastructure. So I think that the off-take agreements are more instructive for those future fuel types that we haven't necessarily seen come into the market, except for the Neste Oil example. Do you have any additional?

MR. HARRIS: Well, I do know that, for example, with the Crescentino plant and Bio-Renewables Crescentino plant in Italy, they do have long-term contracts for the sale of their Ethanol at a particular price.

MR. OLSEN: Okay.

MR. HARRIS: That gives them a certain degree of certainty.

MR. WAUGH: Yeah, I would like to add something about biodiesel, for example, right now according to our reporting tool, we're seeing on the average a B.5, so there's a lot of room still yet on biodiesel to be used in California, and my colleagues at ARB are taking to the Board -- I think they're scheduled for September -- fuel specifications for biodiesel and renewable diesel, and I think that will add more certainty in terms of, you know, that ARB believes in those fuels, and there's fuel specifications for those, and there's still a lot of room to include additional biodiesel in today's fuel.

MR. OLSEN: Just one more question, if I may.

MR. KINNEY: Sure.

MR. OLSEN: This goes to Mary. Your comment about -- both Paul and Mary made a comment about the capital cost and basically a capex cost. Interested in where you think -- is there a threshold point for actual production cost to the sale of the biofuel to the consumer, and what that price range, or what that threshold point needs to be to be competitive with the price maker for either diesel substitute or gasoline substitute.

MS. SOLECKI: Yeah. This is something that we're currently studying and so I don't necessarily have final answers to that yet, but we're very interested in it and, at least looking at KiOR's numbers and Solazyme's numbers, for example, KiOR is coming out at about $10.00 per gallon in capex, and Solazyme is actually, because they've got pretty low financing, they are looking at about $5.00 of capex for the projects that they're currently constructing, which I found amazingly low. As far as the price target that they are looking at, like I mentioned, it's about $100.00 per barrel that they're hoping to be able to compete with oil. An interesting side note to that is a lot of biofuel producers will correctly note that they're providing a superior product because it provides a lot of all the same performance characteristics, as well as better economic implications to the United States, and greenhouse gas reduction, of course. So the incentive to sell at a price cheaper than oil is actually somewhat low, they are correctly arguing that, if they are providing a superior product, why would they sell it at a lower cost. And so what they will actually do with things like LCFS credit prices and RIN credits is a little bit -- I think that will vary company by company about whether they pass that value onto their customers, or whether they will actually tack that cost onto the cost of their product. That, I think, will vary case by case, and that's something that I'm interested in watching in the future and that's what we're looking into now.

MR. HARRIS: POET, for example, has

stated publicly that they can produce cellulosic ethanol for $2.50 a gallon or less in their liberty plan, and based on their capex, probably something like $.75 per gallon of that cost is from the capex, itself. So you can kind of do your own calculations there about what effect that is having on the minimal ethanol selling price and what it would take for it to be competitive with gasoline or with starch ethanol.

MR. KINNEY: Okay, we have another question from online. This is from Russ Teal. "There has been a lot of discussion about the challenges which cellulosic ethanol faces. What do you think are the prospects for using the same biomass for gasification and gas to liquid technologies such as Fischer-Tropsch?" Anybody want to take that?

MR. HARRIS: Well, the thermochemical platform is out of my realm of expertise, but certainly it's potentially competitive, at least the analyses that I've seen from NREL would indicate that it's competitive with the biochemical platform. It is a mature technology and the room for improvement is actually less than it is in the cellulosic industry as time goes on. It's been evolving for decades --

MR. KINNEY: Right.

MR. HARRIS: -- and has reached the point where it is a very mature industry. So, lacking some sort of a technological breakthrough, it's not going to get significantly cheaper than it is currently, whereas I think cellulosic ethanol can potentially get cheaper with additional technological breakthroughs. That's my take, anyway.

MR. KINNEY: I guess a parenthetical question, then, are thermochemical conversions of cellulosic material considered under RFS, are they considered a cellulosic category? So they're eligible for the cellulosic rate?

MR. PARKER: Yes, they are. And they're at their energy content value, so Fischer-Tropsch's diesel -- a gallon of Fischer-Tropsch diesel would net you almost two RIN values, I think, because it's almost twice the energy content. That's a little over-stating it, but -- you get more per gallon, but you get less gallons of diesel out of it instead of similar energy out/energy in. And the other part on thermochemical processes that I keep saying "capital expenses," but they are -- the problem with the study is that they are more expensive capitally, they tend to be a higher capital cost than the biochemical -- looking at the biochemical processes and saying they're too capital intensive. So that's another factor going into the problem with the thermochemical processes.

MR. KINNEY: We have some Applicants who have proposed to repurpose existing oil refineries using beef tallow and some purpose grown crops, and in that case their capex is considerably less because they're not buying new equipment.

MS. SOLECKI: And you're right that that can significantly help their capital expenditures. For example, back to the KiOR case, they need a hydrotreater for their fuel, and a hydrotreater is something like a billion dollars. And so, of course, the cheapest would just be to partner with a refiner that already has that -- in fact, refiners frequently have excess hydrotreating capacity. And so I know that they have looked into that and were unable to come to terms with an agreement that were favorable to both parties, so they decided to buy their own hydrotreater, which drove up their capital expenditures.

MR. PARKER: On the -- what you were mentioning in terms of using the feedstocks you were discussing that can go into better oil, fats and greases, that you're getting into -- if you're only limiting yourself to waste fats and greases and energy crop oil seeds, energy crops tend to be very land intensive, so if you don't want to go into expanding into a lot of cropland, then if you're looking at these pathways that require a lipid that oil, fat or grease going in, you have a limited potential for growth.

MR. KINNEY: Right. Tim, what was the value that we got for -- shall we share that, or no? Maybe not. I don't want to share that, never mind.

Any other questions? If not, it looks like we're going to break early for lunch. Thank you all for your participation, our panelists. Can they have one more round of applause?

[Applause]

(Break at 11:41 a.m.)

(Reconvene at 1:02 p.m.)

MR. MARISCAL: Okay, we're going to go ahead and get started.

So the afternoon sessions for this workshop are going to go a little bit differently than the morning sessions. The afternoon session, Session 2, is going to focus on Biomass to Biopower Challenges and Opportunities. We have our expert panel sitting up there waiting. I am going to give a presentation just before it to kind of set the stage for their presentations and their discussion.

And then we have a presentation from Pat Holley with Covanta Energy and the California Biomass Energy Association, he'll be providing a presentation on the status of the existing industry and also the status of the U.S. EPA's MSHM -- and I hope I got that right -- Regulations.

Panel 3 will be to discuss the benefits and environmental considerations of biomass use in California.

Just a reminder, this workshop is for the Bioenergy Action Plan, Progress to Plan, and the Development of Recommendations for the California Energy Commission's IEPR, the Integrated Energy

Policy Report, so as part of the IEPR process, the Energy Commission makes staff recommendations which may or may not be made into state policy later on down the road, so it's important that if you address or bring up a challenge, please bring up or address a possible solution to overcome those challenges.

And for those on the Web, meeting materials can be downloaded at the Web link at the bottom of this slide. Most of the presentations for today's speakers are available online. And with that, I will get started.

My name is Garry O'Neill Mariscal. I work for the Renewable Energy Office. I've been working as the Bioenergy Lead for our office for the last couple of years. I will be discussing Small-Scale Biopower, the Challenges and Opportunities for Development in California. As part of that, I will be discussing the Benefits and Challenges of Biomass, some of the Policy Drivers, the Bioenergy Action Plan and the role that it plays, the Electric Program Investment Charge, I'll be providing a brief update on that, RPS and CPUC Feed-in Tariff Programs, I will be providing a couple of slides on behalf of the

CPUC. And then SB 1122 Feed-in Tariff, that will be kind of the centralized topic for our panel discussion today.

So the use of Biomass residues provides societal benefits by turning a liability into a commodity value, so if somebody has too much forest waste, or they have too much Ag waste, they can actually use this and turn it into a commodity that they can turn around and sell, as opposed to paying someone to take it off their hands. There are also many environmental benefits, water quality, air quality benefits for utilizing a lot of these materials, rather than leaving them in place, or burning them in place. And it also provides an alternative waste disposal option for a lot of food waste and other material that ends up in landfills. There are also challenges, environmental considerations to take such as there is a lack of private capital for a lot of these projects mostly due to the fact that biomass feedstock, there is not a great long term market for this stuff, you can't sign long term contracts to procure biomass, so therefore banks don't really see this as a bankable type of a feedstock and that leads into the uncertainty of the biomass commodity market. There are pollutants that come out of a biomass facility in many cases, and once you get down to the smaller facilities the air pollution control equipment gets very expensive as compared to the project cost, itself. And then, of course, biomass sustainability, how much biomass should be left in place and how much can be pulled off for energy production?

So in California we have a huge amount of biomass potential. This is, of course, an old graph that was created by the Biomass Collaborative. They are working on updating it, but based on investment back in 2007, there was 36 million bone-dry tons of biomass from urban, agriculture, and forestry sectors. And less than 15 percent of it at the time I made this slide was being utilized to make biopower, bioenergy in general, and then about 60 percent of the materials that we're sending to landfills each year is biogenic material that could be potentially diverted to either a digester or another biomass facility.

So the Bioenergy Action Plan was developed to help address some of the challenges to bioenergy development in California, so the Bioenergy Action Plan is a State level interagency action plan to address the challenges facing the industry and to increase the amount of development from these projects and the energy production from these projects.

The Bioenergy Interagency Working Group is chaired by the Deputy Secretary of the Natural Resources Agency, Ann Chan, and has these various agencies on this slide participating actively in it.

So we recently developed two Bioenergy Action Plans, one in 2011 and one in 2012. The 2011 Bioenergy Action Plan did a very thorough survey of the challenges facing the industry from various aspects of the industry. And then, in 2012, we updated the actions in the plan and the policy directions and objectives of the plan. The challenges remain the same. So these are a lot of the high level challenges that we identified in the 2011 Bioenergy Action Plan which the 2012 was designed to address.

Now, we have made some progress on some of these issues, but it will be some time before we see any steel in the ground as a result of the actions that we've taken, particularly with respect to some of the research and Feed-in Tariff programs that have been developed.

So the 2012 Bioenergy Action Plan set a number of policy goals such as developing environmentally friendly and economically sustainable bioenergy production from biomass waste streams, and then encouraging the development and deployment of energy technologies to produce localized generation, distributed generation facilities, particularly three megawatts or less, also job creation. And then reduce the fire risk and improve water quality and reduce waste.

So this is a brief summary of some of the actions that were contained in the 2012 Bioenergy Action Plan, I'm not going to read through it, just basically it covers that we're going to be doing some actions related to research.

EPIC, there's an amount of funding, roughly $27 million in the first investment period that the Energy Commission has proposed to set aside for bioenergy projects, and then streamlining and consolidating the permitting process for new projects.

The whole purpose behind the Interagency Working Group is to provide interagency coordination on developing the Action Plan and to administer the actions within the plan, and to keep us talking together.

The working group actively meets quarterly right now to discuss the Action Plan and our progress towards achieving the goals and the objectives of the plan.

The Energy Commission is tasked with measuring the progress and keeping track of the actions in the plan and what tasks have been completed and have not been completed, and developing a report every two years for the Governor and for the Legislature to see what our status is for development in California. And so that is the process that we're working on right now.

So this summer, as part of that process, we'll be releasing the 2013 progress to plan, hopefully late this summer, and then a summary of the recommendations from that will be put into the 2013 IEPR. So on the Electric Program Investment Charge, this program was developed and established by the California Public Utilities Commission, and is overseen and administered by the California Public Utilities Commission. The Energy Commission is one of four Administrators of that charge and our Investment Plan was proposed and submitted to the CPUC last November. The CPUC staff recently released their proposed decision to accept that plan and we hope to hear early summer whether or not that plan gets adopted by the CPUC.

So this graph is just the Technology Maturation curve, this is kind of the backbone of the EPIC Investment Plan and the way we based and structured the plan. It provides -- the EPIC program is designed to provide funding for two Valleys of Death within the technology maturation curve where good ideas tend to go basically to die. There is not enough private capital out there, or there isn't private capital to provide funding for these projects. The bioenergy projects that we're going to be talking about today are going to fall into Stage 3 and Stage 4 of the Technology Maturation curve. Now, it's demonstration and deployment and commercialization of these technologies.

In our first Investment Plan, as I have mentioned, we proposed offering setting aside $27 million for the first three -- a minimum of $27 million for the first three-year Investment Plan for the demonstration and deployment of bioenergy technologies.

So this is just the funding areas and definitions from the EPIC program. For technology demonstration and deployment, we're talking about the installation and operation of pre-commercial technologies or strategies at a scale that is sufficiently large and conditions sufficiently reflective of the anticipated and actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks. That's a lot of words and a really long sentence to basically say that we're looking at pre-commercial technologies that have not been deployed at large scale in California. So a lot of the bioenergy technologies that we're looking at, at really small scale, have not been deployed at large scale in California, so we're talking about small half megawatt gasification facilities, or dairy digester type operations.

And even what we're looking at is strategies to help get these projects to become more economical, so if we're talking about feedstock, transportation, or other innovative approaches that will reduce the feedstock cost and transportation costs for these facilities to make them more economical, that may also be considered as part of the projects.

So this is the proposed funding criteria for the EPIC Investment Plan, I'm not going to go into it. It just shows, again, that the match fund requirement, or that the minimum for a technology demonstration is going to be the $27 million for bioenergy. The match fund requirement on here, I just want to point out, is going to be 20 percent of the requested EPIC funds, that's the minimum match fund requirement. Of course, if you propose a higher match fund requirement, that'll give you a higher score.

So I'm going to step over and change gears a little bit and talk about the Renewables Portfolio Standard, which is a market-based program that requires all retail sellers of electricity to procure increasing amounts of renewable energy through 2020. Right now the

2020 goal is 33 percent from renewables. And then this just goes into the history, the three largest IOUs are PG&E, SCE, and SDG&E. According to the CPUC, they have procured more than 20 percent of their 2011 energy from renewables.

The statutory goals for the RPS are displacing fossil fuel, building new renewable capacity, reducing GHG emissions, and providing reliable operation of the grid and, of course, stable retail rates. And I think the bioenergy meets all of those statutory goals.

And this is a CPUC slide, kind of providing an overview of what is the difference between the CPUC and the CEC when it comes to the operation of the RPS and the administration of the RPS. The CPUC is responsible for overseeing the IOUs' implementation of the RPS and overseeing their contracts executed under the RPS program. They also take care of the resource planning for renewables, procurement and compliance targets, and imposing penalties for noncompliance for the IOUs.

The CEC is responsible for certifying renewable generating facilities as RPS eligible, and overseeing the POU RPS programs.

This slide provides a visual representation of the difference between the RPS solicitations and the amount of capacity that's going to be assigned to meet the 33 percent RPS requirement by 2020 compared to the Feed-in Tariff programs that are out there, and you can see the Feed-in Tariff programs are much smaller than the overall RPS solicitation program, the RFO process.

And on here, the subject of this panel is going to be to talk about this SB 1122 Re-MAT, which is 250 megawatts of bioenergy.

So the Renewable Feed-in Tariff Program, which the SB 1122 Feed-in Tariff Program will become part of, was originally enacted by AB 1969 back in 2006, and I believe it was originally focused on wastewater treatment plant projects. It has gone through various revisions in the last few years until SB 32 changed the program to a Renewable Market Adjusting Tariff program, which the CPUC is in the final implementation stage of this program. SB 1122 is a set-aside within that program, which adds 250 megawatts to the 750 megawatts in the SB 32 Feed-in Tariff. It sets program targets for -- I'm sorry, it sets limits for project sizes for various capacity in different resource areas, so we have forest biomass, wastewater MSW, and food waste, and then dairy and Ag bioenergy. The projects are up to 3 megawatts in this Feed-in Tariff, and the price structure that they're proposing at this time is probably going to fall under the Re-MAT price structure.

So this is the implementation process for SB 1122 for CPUC implementation. On April 9th, the CPUC released a Draft Consultant Report titled "Small-scale Bioenergy: Resource potential cost feed-in tariff and implementation." On May 2nd, CPUC held a staff informal workshop. On June 4th, workshop responses from parties were due to the Energy Division staff. And then by the third quarter of 2013, the CPUC plans to release a staff proposal on the SB 1122 implementation.

So these are now back to my slides. Reading through the report and looking at the implementation of SB 1122 and talking to some developers, these are some of the challenges that I've heard regarding where we're going with SB 1122. So it seems that, based on reading the report, that the projects that are going to be targeted by the Feed-in tariff have not been successfully commercially demonstrated in California, and it seems to me that at least the Re-MAT Feed-in tariff kind of requires that an approach, or a project, or a developer be from a commercialized technology, or a commercialized approach in California, so there might be a difficulty with implementing SB 1122 if we're looking at pushing pre-commercial technologies out to market right now.

The resources that we're looking at, biomass resources, are generally in regions where there is not a lot of load, so we're going to have high interconnection costs and then the Re-MAT, there is a currently a screen in the Re-MAT process for interconnection costs that generally need to be lower than $300,000 or $400,000. And a lot of these bioenergy projects are looking at interconnection costs that are in the range of $500,000 to maybe $2 million. The Re-MAT price mechanism which sets the tariff level, it may be slow to react to the market, there may be other challenges to it, that remains to be seen, but many people see many problems from many different sides to the pricing mechanism in Re-MAT for the Bioenergy Feed-in tariff, so hopefully the panel can weigh in on that a little bit more.

So overcoming these challenges, the Energy Commission sees that the EPIC Program may be able to be used to target solicitations at SB 1122 eligible projects to help reduce the cost to the utility ratepayers. One of the ideas is also to recommend considering modifying the Re-MAT price mechanism until more technologies are developed and commercialized in California.

And then also we really need to continue to review the interconnection costs, or the interconnection issues for these small-scale generators. The CPUC and the Energy Commission is doing a lot of work to look at and study these issues, but more work still needs to be done.

Okay, so if you were looking for more information on the CPUC's RPS proceedings, these are the contacts and these are the links for you. Adam Schultz is the lead analyst on the Re-MAT Program and the implementation of the SB 1122 Feed-in Tariff, and this is contact information up there. I will do my best if you have any questions to answer any questions about SB 1122, but I am not an expert. And then, after that, I will go ahead and open it up to any quick comments on my presentation right now, and then, if there are none, I will move over to the panel. Are there any questions? No? Anything on the Web? Okay, with that I will hand it over to the panel.

Karen, we'll start with you and if you wouldn't mind introducing yourself and I'll put your presentation up.

MS. KAHMOU: Great. I'm Karen Kahmou. I'm the Manager of the Renewable Energy Policy Team at PG&E and the Energy Procurement Organization. So thank you so much for having us here today, we appreciate the opportunity to talk to you about the renewable energy market and bioenergy.

Today I want to cover three broad topics. I want to go over where PG&E is in terms of meeting our RPS targets, as well as talk about the various bioenergy procurement opportunities that are currently available, as well as address some of the challenges, the deploying bioenergy within our state.

So this is a quick slide to just give

you an overview of our company. PG&E's mission is to provide safe reliable and affordable electricity to our customers. We serve about five percent of the U.S. population, but in less than one percent of the CO_2 of the total utility sector.

And here we dive into the first topic. We've signed over 141 contracts for over 10,000 megawatts of energy since 2002, and the picture on the right shows you essentially we have procured generally the IOUs, as well as others throughout the state, and then throughout the WECC a little bit, so generally we're not always restricted to our service territory, however, SB 1122 and some other programs do restrict us to our service territory. And it's important to note that this table also doesn't include the 100 contracts we've signed under the Feed-in tariff program for over 100 megawatts, as well. And another thing to note is that the utilities since the '70s have not been able to -- we don't make money based off of selling electricity to our customers, so we file these contracts in front of the CPUC and, once the CPUC approves them, we send those costs without marking them up, straight through to our customers, so they pick up the full costs of the RPS Program.

With this slide, I want to show you where we've been in the past, where we are today, and where we're hoping to get to. We're at 19 percent actually in 2012, but by the end of this year, we anticipate about 1,400 megawatts of renewable energy coming on line in our portfolio, and by the end of 2014, another 1,200. So combined, I think in 2013 and 2014, you'll see the largest growth in our portfolio are equal to the nine previous years of the program, so it's a significant growth in two years that we're going to have, which is to show that all the contracts we've been signing over time are finally coming on line, which is an exciting time for us, and 2013 is actually the first year that we're going to reach a compliance target before the bills have changed the targets, so it's kind of an exciting year. We're going to be prepped to do that by the end of this year.

Here, I just wanted to show you our general power mix. This is our 2011 power mix, our 2012 is due to the CEC this month, so we'll get that out soon, but we expect it to look similar to this. You can see the pie chart we have, and 19 percent renewables, as I mentioned, and it's made up of bioenergy, geothermal, small hydro, solar, as well as wind. But the amount of energy that we deliver to our customers is 60 percent zero GHG, which would include the large hydro, which doesn't count for RPS, it's not RPS eligible, and nuclear. So when you take that all into account, our energy is actually pretty clean.

With this slide, I wanted to dive a little bit deeper into our bioenergy. Bioenergy has helped us get to where we're at, essentially, it's played a large and consistent role in our portfolio, and we expect it to play a role in our portfolio. In 2012, we procured over 3,000 gigawatt hours of bioenergy, which represents over four percent of our total load. And if you were to just take a percentage to see what percent that is of the 19 percent, it's about 23 percent, so it's quite significant.

Here, I wanted to put it a little bit more in context. Amongst the three IOUs, PG&E procures 70 percent of all bioenergy and over 80 percent of all biomass contracted to IOUs in

California. So we are -- and our peak load is 40 percent of the state's peak load, so certainly it's above our proportional peak load share in the state. So that was the first section where I wanted to talk about where we are in terms of RPS, and then the second section I'll talk about how we procure renewable energy.

With this slide, I wanted to show you the various renewable energy programs. The bars in yellow we call "behind the meter", that little circle is supposed to represent a meter, and the behind the meter is the customer side of the program, so they generally don't count for RPS. And then the blue bars are programs that are wholesale, which do count for RPS, and on the X axis, we show you the different sizes. Certain programs have certain eligibility in terms of size, and as you can see, some of them overlap. So currently our focus is on procurement that helps us meet and then sustain our RPS, 33 percent RPS, in a cost sensitive manner for our customers. So as we continue to procure, we use these various solicitations to procure the least cost, best fit projects for our customers.

The Renewable RFO, we held our 2012

Renewable RFO at the end of 2012, and we're in the process of finalizing that short list, and any project can bid into that above 1.5 megawatts and bigger, any technology is eligible. The CPUC, I think it was May 9th, released a ruling asking the utilities to develop their 2013 RPS procurement plans, and we're in the process of doing that right now, and they're due June 28th to the CPUC.

And we also have the Re-MAT which Garry touched on, Re-MAT, the CPUC issued its third and final decision in the Re-MAT Program, and we expect it to start in the fall. It has three buckets, baseload energy, peaking is available, and then non-peaking is available, and it's for projects that are three megawatts and under.

And of course, we have SB 1122, which the CPUC -- you saw the chart that Garry had, had kick started that proceeding in May by releasing the Draft Black & Veatch report.

We also have the Renewable Auction Mechanism, that's the RAM. We just issued the RAM 4 on May 28th and we expect bids to come in by June 28th, and that program is available for -- has the same three buckets as Re-MAT, and it's for projects sized 3 to 20 megawatts.

So as we continue to procure energy that the CEC determines is RPS eligible, we see three broad challenges to deploying bioenergy in California: that touches on price, the value of baseload, and the value of being able to curtail and being flexible, as well as societal benefits, which I believe the panel after us is going to be touching on. So we're doing this all -- and I think Garry had it in his slide where, you know, the overall principle of the renewable energy market is competitive procurement, so we do all of this with that guise overseeing us.

So because we've procured from various projects that are available, some existing projects, some new projects, various technologies with various sizes over the past nine, 10 years, the price of renewables have come down and this is recognized in the CPUC reports. The SB21X asks the CPUC to submit reports to the Legislature, and the CPUC did that in March and showed that renewable prices have been coming down. And so, because of the unique fuel aspects of bioenergy that others have also touched on, it does make it challenging when you look at bioenergy in comparison to alternative renewables that can also help us meet our 33 percent RPS standard.

We think one way that bioenergy can address this price gap is to provide flexible capacity. This is a slide we adapted from the CAISO. The X axis shows you a 24-hour period and the Y axis is the Megawatts that come on line in the CAISO system. And this is a day in 2020, and it's a net load of the state minus solar and wind. And it shows you that that valley gets really deep, and so as intermittent renewables come on line, conventional -- or baseload resources have to curtail off because we have a loading order requirement. And so we need to be able to ramp down and then ramp up really quickly, and so this can create operational issues for the grid and, as you saw, the definition that Garry had on there was that RPS is supposed to also help keep the reliability of the grid going. And so one thing that this resource can do is to help bridge the value gap by managing this operational flexibility and I think that adds value.

With this slide, I basically want to show you, you know, energy procurement is a very complicated balancing act that we administer. It has not just one or two, but multiple stakeholders from multiple technologies and multiple groups, so that's why we're here today, to be able to listen to various stakeholders, that's why we participate in all of these proceedings. And we do think that societal benefits should be quantified and I believe the panel after us is going to talk about that, but the Bioenergy Action Plan also indicates that this is unprecedented and that it is difficult to calculate, so I think within the next year, the Biomass Collaborative is going to be trying to do that, and we look forward to participating. But, so as we put a dollar value to that, the question becomes, who should pay for it? And where should that money come from? Should it come from electric Ratepayer? Should it come from the generation component of electric Ratepayers for societal benefits?

So in summary, I just wanted to go over, you know, we are on track to meet our 33 percent RPS standard and bioenergy has played and will continue to play a role in that for us. There are multiple solicitations that are currently available for bioenergy to participate in, but as we go forward and value this, we need to balance what is the price and what is the value and who should be paying for it. Is it PG&E electric customers? Is it just IOU electric customers? That discussion needs to happen and it needs to be part of what we do as we go forward. So thank you very much.

MR. MARISCAL: Thank you very much, Karen. That was a great presentation. I'm going to turn it over to Fred Tornatore, TSS Consultants.

MR. TORNATORE: Well, I'm happy to have been invited to give a presentation. My presentation is going to focus primarily on the forest sector of bioenergy.

Oh, the standard ad for TSS, we've been in business since 1986 and we focus on biomass to power, but we also continue to help project developers, government utilities with all forms of bioenergy, including biogas, biofuels and bio products, biochemicals.

So why biomass to power? I guess you could almost substitute in here between the "why" and the "biomass" "forest-sourced biomass power." Obviously, as has been mentioned, it does have societal and environmental benefits that are difficult to monetize. It does create long term jobs, it takes people to gather up the forest-sourced materials to take to facilities for utilization. You can also solve waste issues. Principally a lot of forest biomass is piled and burned after thinning operations or harvest residues, creating a fair amount of uncontrolled air emissions. A power plant is a controlled environment to take care of those emissions. Also, it can improve forest health and mitigate wildfire occurrences through thinning operations.

So the situation, the Investor-Owned Utility territories have substantial acres of both forest and wild land in medium to high threat of wildfire, it's like 25 million acres, which is 25 percent of the total land of California. Also, climate change may be increasing this wildfire danger.

Take a look at the map of California, that reddish stuff and the yellow stuff are the medium to high fire threat areas; obviously, lots of it is the desert down in the southeast corner, but as you can see, Northern California, Central California, both in the mountainous areas, there's a fair amount of high threat of wildfire danger.

So Forest Thinning and Biopower. Wildfire hazard is reduced by removing the excess biomass fuel. Power generation in small, distributed systems has advanced over the last few years, but still in the pre-commercial stage, at least in California. Such power plants, as I mentioned, have a place to take the hazardous fuels, rather than pile and burning it out in the field. However, this potential opportunity comes with the challenge of cost. And I'm going to kind of bounce back and forth between opportunities and challenges. This is sort of my dyslexic personality.

So I want to show a slide here that shows some of the positive effects of fuel treatment, I don't want to go into great detail because there will be some discussions probably later on about environmental considerations. But as you can see, the area that is burnt was an unthinned area, the fire moved from left to right in this photo, and in the thinned area you can see that the trees did not all burn down. The fire was able to go through that area without going to a ground fire and creating a catastrophic wildfire.

So what are some of the challenges? Well, the high cost of feedstock, collection, processing and transfer, even though that material is sitting out there in the woods, after being piled after either harvest or thinning operations, material needs to be processed, i.e., chipped, it needs to be moved by vehicle, generally a large diesel truck, and also there's just the general collection of the material in some instances, which actually adds to the pretty high cost of fuel forest biomass. Our range of numbers that we use is about $45.00 to $60.00 a bone-dry ton to bring that material to a facility, even though we're getting the material on the ground basically free, it's just all the other costs of getting it there.

But there's no ability to pass through increased cost of labor or diesel in Power Purchase Agreements. Diesel has gone up quite a bit and it's adding quite a bit to the cost of moving the materials. Also, financial markets as in any bioenergy arena are hesitate to support early phase technologies such as gasification. And we have been very big on gasification technologies because of the much less environmental impacts on gasification technologies that electricity have over, say, direct combustion. Not all stakeholders -- sorry to put that in there, Kevin -- are on board, there are some groups that don't agree with us, and sometimes we welcome disagreement because it just hones our senses better.

Also, there are small scale biopower economies of scale. We see this just in the difference between a one and two megawatt power plant. It takes just as many people to run a two megawatt as it does a one. Op Ex are operating expenses, you know, and one of the highest is labor. So all those translate into some significant costs.

Well, Garry went over these quite good in detail, so I really don't need to, but the main focus for us, obviously, is Senate Bill 1122, and the Bioenergy Action Plan, too, is a great thing, too. It has really helped to focus a lot of issues at agencies back on bioenergy.

The reason I'm showing this slide is, of course, the 50 megawatts from sustainable forest-sourced biomass. And again, that biomass for the forest must come from the high wildfire hazard areas so it's just not all over the place, but in California unfortunately most of the forests are in a high state, or medium to high state of wildfire risk.

Why is 1122 needed? Obviously just the price of power has gone down. And up to 2008, things were looking pretty good for bioenergy as the price escalated, but then, as you looked just in the major drop of avoided cost -- I'm not quite sure which utility this is for, I think it's PG&E, that line has dropped down significantly.

So what do we see? One of our major areas that we're trying to deal with in the forest-sourced biopower is a lot of it to do with pre-development challenges, and a lot of that has, again, to do with funding, as you can see, difficulty in obtaining feasibility study funding, issues regarding stakeholder and community support, difficulty in obtaining funding -- I got that in there twice, sorry about that -- delays and challenges to the permitting process, utility company interconnection and contracting issues and costs, delays in development of implementation of PUC policies related to pricing and power purchase agreements. I mean, even with the 1122 process, we're looking at, once the PUC gets the whole bidding process or the auction process going, we're looking at a good year before that price may get up to what we basically will need for standalone forest-sourced bioenergy projects, and that's in the $.14 to $.15 per kW hour range. And these costs up here that I talk about really are costs before so many times a project developer is actually even brought on for a sourced project.

And here are some of the pre-development costs. And these are really sort of a hang-up for us because most of the forest projects are a lot to do with communities that are interested in doing them, and resource conservation and development councils, and other community development councils that are looking to do a variety of things with forest-sourced biopower, one being just -- one project that we're working on, they're looking to -- there was a sawmill there at one time for a number of years, it went away, and they're looking to repurpose that industrial land for uses to create economic development and jobs in the area. So these costs that we have here are the predevelopment costs that we are struggling with, scrambling with many times to fund. I put it in as a range, so it goes anywhere from $168,000 to $765,000, it could go higher. Obviously, one of the major components is CEQA and other permit preparation. I mean, it's not that CEQA -- not doing CEQA or looking at environmental impacts or environmental considerations is really the issue, it's the cost of doing it. We don't -- we're trying to be green power, we don't want to come in with a bunch of environmental impacts. But it is costly. Someone has got to pay for it. And in the pre-commercial level that we're in with bioenergy, there's not a lot of project developers out there that are willing to put that money in, so we have to look for the different ways of funding it, sort of the tin cup approach, I like to call it. You know, "Please, sir, more gruel."

So, going on to what -- getting here

towards the end of my presentation, one of the things that Garry wanted to talk about was sort of the path forward for the forest side. Obviously, and it looks like this is working, is the full implementation of SB 1122, that will garner higher PPA rates for forest-based biopower. So we'll see where that goes, we've still got a lot of months before we see if we get there.

Also, allocate dedicated funds to AB 32 Cap-and-Trade and the EPIC Investment Plans, and that certainly sounds like that's moving forward. We would like to add that we see technology talking about, you know, technology demonstration, etc., but we really want the Commission and the PUC and other agencies to realize that there is a need for some of that upfront money, the predevelopment, the preliminary and also these predevelopment costs that really would get a lot more projects out there going.

Some of the other things that we're thinking about was instituting a loan guarantee program for forest-based biopower. I think that's pretty important. I heard one KiOR got a big giant no-interest loan, and that would be fantastic. With these technologies in this pre-commercial stage, even if you can find financing, I'll tell you, it's expensive stuff, it's pretty high interest rate on it, it would be great to get that down to much lower, even to zero, or have a loan guarantee program at a low rate, but then also the low interest loan program which, you know, CalRecycle has for projects in the Recycle Market Development Zone? Yes, thank you. It would be great for that to be something where you would have it in the high fire threat areas, I mean, you could just look at it in that format. And then, of course, and I really like this, is fully implementing the California Bioenergy Action Plan, there's a lot of great things mentioned in there. If we could implement all of them, I would be overjoyed. And with that, that's the end.

MR. MARISCAL: Thank you, Fred. Next is Michael Boccadoro with the Dolphin Group.

MR. BOCCADORO: Thank you. Good afternoon. I'm Michael Boccadoro, President of the Dolphin Group. I had the pleasure of being actively involved in renewable energy policy in

California probably for about the past 20 years. I've been particularly involved in development of the state's FIT program policies with the passage of legislation in Sacramento. And I've worked closely with the dairy industry, and so a lot of my comment will be focused on that sector today since Mat and Fred are doing a great job of talking about some of the other sectors.

Dairy digester development in California has really lagged. We have the largest dairy industry in the country, we have 1.8 million cows, those are milk cows, a significant potential to develop biogas, biomethane, and to some degree vehicle transportation fuel from significant resource that we have in the state. We have four current projects that I'm personally aware of that are in development in California, two are in the SMUD territory and two are in the PG&E service territory. But for the most part, project development has stagnated in recent years for a number of reasons and Matt can speak to this better than I can, he's done a fairly thorough analysis for the California Energy Commission, but roughly we've had 24 projects built in California, all with some level of subsidy, but fewer than a dozen, I believe the number is 11 today, are still operating. So we not only haven't developed new dairy digesters in California, we've actually lost a significant number of the digesters that have been developed, many with State funding support. So we're doing something wrong, I think that's a core message that you'll hear from me today.

There are a number of reasons why. Permitting obstacles and complexities certainly slow down the development of dairy digesters in California. We have our dairy industry in California in a significant non-attainment area in the San Joaquin Valley. NO_x is a critical issue and, to the degree that you're using internal combustion engines to generate electricity, you're going to be throwing off some NO_x, and so that has been a significant issue.

But the regulators and State leaders have stepped up to help streamline that process in terms of permitting. A programmatic EIR has been completed that was a collaborative effort by the Water Boards and the Air Quality Management Districts in California, as well as CDFA and other entities, and made that process I think much more straightforward. We can get projects permitted today, there's no question about that, that's not the obstacle anymore. Those permitting requirements do add to our environmental compliance costs, and that of course hurts economics. You'll hear me talk a little bit about economics and how those higher compliance costs are impacting it.

Frankly, the single largest issue and obstacle for the development has been the lack of long term Power Purchase Agreements. I think you heard PG&E describe a number of programs that they have that are in operation, but frankly none of those have resulted in significant long term power purchase agreements, which was really the reason why we were back in front of the Legislature with 1122 last year because, while we've had good intentions, we've created a number of programs that I think were designed to help encourage bioenergy development, but for one reason or another they have failed to do so, and so 1122 really becomes critically important in that environment.

We also have immature carbon markets and we've got a lot of programs, Cap and Trade being one of them, but until that market matures it's difficult to finance projects based on a revenue stream that's uncertain going into the future. You're really limited to your Power Purchase Agreement in terms of your ability to finance projects, and you'll hear that from project developers that you talk to.

Without a doubt, the second largest issue is the difficult and uncertain interconnection process. Garry touched on it a little bit in some of these rural areas where you have dairy and some of the other bioenergy projects where you have the resources, we're seeing high interconnection costs. And the process is difficult, it's costly upfront, and most importantly it's uncertain. Even when the utility gives you an interconnection cost estimate, it oftentimes comes in much higher once you're down the road financing your project, only to get the rude awakening of PG&E missed their estimate, and guess what? It's not going to cost you $250,000, it's going to cost you in excess of a million dollars. Suddenly your project is upside down.

High financing costs, you know, all

driven -- you heard Fred talk a little bit about the cost of financing these projects, there's a lot of risk associated with them for all the reasons I've just outlined, and people providing financing for these projects want a high rate of return, and so the cost of financing these projects is very significant. And then unfortunately, Federal incentives are declining. The biggest Federal incentive that we had for electricity projects was the ARRA 1603 grants. If you don't have your project safe harbored, you don't have it on line by the end of this year -- operational -- you're not going to be eligible for that 30 percent going forward; some of the projects that I discussed in the first slide, they are still eligible for 1603, and we're desperately trying to get them on line by the end of the year so that they can take advantage of that.

So a little bit about the outlook for the future. If you were going to kind of crystal ball California and look at it from bioenergy development, and you were looking at it from an outside standpoint, the regulatory environment really seems to have encouraged digester development in California. AB 32 Cap-and-Trade digesters, particularly dairy digesters, are an amazing way to create credits under the Cap-and-Trade program. Methane capture and destruction is a significant benefit that dairy digesters can provide to the system. Our RPS program, which you've heard a lot about today, also would seem to encourage bioenergy development in California. The Low Carbon Fuel Standard, to the degree you're making vehicle fuel, the Low Carbon Fuel Standard can provide some significant revenue streams in terms of biogas and bio digester development in the state.

And then our urban waste diversion goals, so this isn't a dairy issue, it certainly is an issue for other digesters that are being developed around California and bioenergy that's being developed. As we divert more and more waste from our landfills, there's going to be increasing resources available to produce bioenergy from that waste.

We have a very supportive Brown Administration, and I'm very happy about that. This administration seems to get bioenergy, they've helped us make an investment with their signature on significant pieces of legislation, including 1122, but in addition to the Brown Administration, the Legislature has also been very supportive of bioenergy. AB 1900 and AB 2196 also passed last year, in addition to 1122, which will make bioenergy to biomethane much more realistic as we move forward in California. So taken today, our policy makers really seem to be very supportive of bio energy and we're very supportive of the argument that, yes, we need to pay a little bit more for bioenergy going forward, get bioenergy on line with the long term goal of being able to bring the costs down, much like we've seen with solar and wind energy in California. It's not going to happen unless we start to build some projects. And the Legislature and the Governor's Office seem to get that. I'm not sure that the Utilities in California are quite there on that same page. You heard a lot about price come up in PG&E's presentation today, and in some of the 1122 workshops that we've had we heard the price argument brought up. But it's real clear, the Legislature listened to the arguments that bioenergy was going to result in a higher price, that was the main argument presented by PG&E and Southern California Edison, it was the main argument presented by the Division of Ratepayer Advocates in their opposition to 1122; they get it. They said we want to do this anyway because it's important to Californians. And we need to translate that policy now into an implementable program at the Public Utilities Commission and quit having this argument about price. The Legislature spoke, it's not a significant impact to Ratepayers, the Legislature and the Governor's Office got that, let's move on. And so that is a very significant frustration for me as we continue to have these discussions.

But the evolving landscape is a good one, I think. Lots of reasons to be encouraged. AB 1900 will clarify and facilitate biomethane injection requirements. PG&E and SoCalGas both tell us that dairy biogas is not a significant problem, most of their concerns relate to landfill, and so we are hopeful that we'll have better access to the state's gas pipeline system. AB 2196 established rules for the use of biomethane as an RPS-eligible fuel going forward. Dairy and other in-state wastewater treatment agency biogas should have no problem meeting those biomethane requirements. And there should be a new market for biomethane as we move forward in California. It's probably going to take a few months as some of the dust settles from that moratorium that was recently lifted by the Energy Commission, but as that moratorium gets lifted, I think what we'll find is that California projects are ideally positioned, frankly because they're the only ones that are likely to qualify. I think it's conceivable if you had a project on state's border, in another state, you might be able to meet the environmental requirements that are included in the AB 2196 requirements. But I think for the most part what you're looking at is state projects going forward that are going to be eligible. The SB 32 FIT program adopted last week includes the Re-MAT mechanism, it's problematic for bioenergy which is one of the reasons why during the three years that it took the Commission to get SB 32 implemented, it passed in 2009, I think a lot of us recognized that it wasn't going to work for bioenergy, and so we immediately started working in early 2012 on SB 1122, long before SB 32 had even been fully implemented.

Long delays associated with the Re-MAT process, particularly for bioenergy if you're starting at 8.9 cents, and competition from existing projects. One of the other pitfalls we sought to avoid with 1122 doesn't apply to existing projects, just new projects. And so from that standpoint, now that we're putting a lot of stock, as I think you heard forestry and Ag and the urban waste projects in California, in Senate Bill 1122, you know, I've heard it called a carve-out for bioenergy, we like to think of it more as an incubation program, that's the way we described it to the Legislature, that's the way we sold it here in Sacramento, and that's the way it's really designed, is I think we all believe that if we can get 250 megawatts of good projects built in California, we can bring down the cost to where they're much more competitive. Without actually building some projects, we're going to be taking about bioenergy for eternity without getting anything accomplished. We're at the early stages of implementation, as you heard it's going to be at least a year and probably longer before the program is even on line, and the Black and Veatch study pointed out that it could be at least a year and potentially longer that, once you got the program on line, I think they estimated out as much as three years until the price could rise to a high enough level if we don't do something about the Re-MAT program, that it could be up to three years before you actually saw any projects getting built under 1122.

I'm also very encouraged by long term vehicle fuel opportunities related to dairy biogas. We're in the middle of doing a USDA study on dairy clusters and one of the opportunities we are looking at is vehicle fuel from that large cluster of dairy biogas projects. So for all of those reasons, I'm somewhat encouraged. We've got a lot of work ahead of us in making sure that 1122 does get fully implemented. EPIC and the Cap & Trade investment funds are going to be important to bioenergy moving forward, but frankly without a workable SB 1122 program, that money would probably not be well spent. So, thank you.

MR. MARISCAL: Thank you, Michael. Next, we have Matthew Summers with Summers Consulting.

MR. SUMMERS: Thanks. I appreciate it. And to Garry, thanks for putting this panel together. I think this has been very useful and interesting to hear the different perspectives. I'm going to be wearing two hats here, one is as principal of Summers Consulting, presenting some data from a study we finished up with the Energy Commission looking at dairy bio digesters, and I'm not here to present a final report for that study, I'm just going to present you with some tidbits related to the topic of this workshop, but the reports for that study will be available as soon as we can get them published up with the Commission, so if you're interested in that topic, you can contact the Commission and get those reports, which they're in the process of being published. Also, I'm Chief Operating Officer of West Biofuels, which is a company focused on bioenergy here in California and I'm going to present a little bit about agricultural opportunities in the biomass sector here in California.

I like to put this little circular thing up when I talk about bioenergy because this is sort of the neatest thing, the thing that everybody sort of gets when you talk about a bioenergy project, is that basically we're taking materials that come from the community, whether it be forest materials, whether it's dairy manure, or even some sorts of municipal biomass, taking those and converting them into energy, and that energy goes back to the community. So this concept of keeping energy local, I think, is the neatest thing that everybody can basically understand about this technology. And when it's been put to the public whether or not this should be done, this concept is actually even more powerful in some ways than price, and I think that's why things like SB 1122 have made it through Legislature that represent the public, is because the public gets this, they get the concept of having this sort of local source of power. And I've also listed a few other things that have already been mentioned today.

I'm going to give you a little bit of information. I'm not going to go through every detail of this, but we looked at for the Energy Commission through their RESCO Program, Renewable Energy and Secure Communities Program, we were contracted to look at six different dairy digester facilities and do a complete front to back end evaluation of the mass energy balances and the economics of these projects, and this is the six facilities is actually seven facilities that we got started with, and one of the facilities went out of business, so we added another facility during the study. But it turned out that six we actually analyzed were either power projects or combined heat and power projects, and different types of digesters.

Digesters aren't as simple as a wind turbine or a solar panel, PV solar panel, they're actually pretty complex integrated systems, integrated with some other facilities, in particular at a dairy you've got the sources of feedstock which is manure coming into a system which retains those manure solids, converts it into biogas, the biogas gets cleaned, and then goes to another system which is an engine generator, and in the case of this study all the projects were engine generator systems. And then that engine generator produces heat and electrical power, and both of those are utilizable sources of energy. So there's some complexity to the system and it is integrated with the operation of the dairy in a unique way, so there's a fair amount of complexity and we had lots of different sampling points that we had to take care of during our study to get an assessment of where all the mass and energy goes in the system.

Just a quick summary of some of the results and, again, you can refer to the full report, but anaerobic digesters convert the manure solids from in the study we saw from 29 to 62 percent conversion in the digester, and when you add the solid separation that's 52 to 76 percent of the manure solids, they're actually removed from the liquid slurry at these facilities, which is a great benefit for future use of the nutrients and other materials that are in the manure. The manure is stabilized, and we showed this with real date, not just sort of speculation, stabilized in terms of oxygen demand and biomethane potential. So manure that goes through a digester has less chance of releasing any methane into the atmosphere because you basically have released that methane within the digester system, which is the greenhouse gas benefit of the system.

The nutrients we showed were conserved within the system, so nitrogen, potassium, all the various nutrients were conserved, and that's an important thing for agriculture because they want those nutrients to go back to the cropping system. Nitrogen tended to convert towards ammonia form, to different percentages and I didn't put those up there, but that's a good thing because ammonia is more predictable in terms of how a crop is going to uptake that nutrient, whereas the biological form of nitrogen or the carbon imbedded form of nitrogen is less crop available and less predictable in terms of where it's going to end up in the cropping system, and potentially a higher threat to water systems in that form.

Methane emissions from the dairy, from these dairies, were reduced 60 to 70 percent, so the manure methane emissions were reduced by a significant amount.

We had some different efficiencies we measured, electrical efficiency and heat recovery efficiency for an overall efficiency of 42 to 66 percent in the study. The most probably significant economic measurement was the actual capacity factors that these systems operated at. We had two systems that hummed right along at 80 percent capacity factor, two systems that were in the 50 to 80 percent capacity factor, which would be considered fairly low for this type of co-generation system, and then two systems which I would say were performers in terms of their economic performance, less than 50 percent capacity factor.

The opportunity here with the number of cows and the population that Michael talked about, we've got 120 gallons of manure per cow, those volatile solids can be turned into 50 cubic feet of biogas. These great potentials for natural gas replacement, you know, petroleum replacement if we're talking about compressing the biogas and using it in transportation vehicles, or some form of that, and then in terms of co-generation, which is what we're talking about here, a large number of kilowatt hours and Btus of heat that can be used. Co-digestion increases these numbers. So supplementing the manure with some other off-site material, or even on-site in the case of a facility that processes cheese or something like that, that increases the numbers by quite a bit, and a significant bite out of atmospheric methane emissions in terms of the state if a greater number of dairy digesters are implemented.

Economic challenge. So in our study -- and these are unsubsidized numbers, so these are unsubsidized capital costs, and so I've got two facilities here that are in red. I kind of consider these facilities -- these were the ones with the low capacity factors below 50 percent, so that inflates all these numbers, but those two facilities, you know, at $.30 per kilowatt hour costs are not in any scenario going to be economically feasible in the near term with what kind of utility contracts they can get, and were -- I would consider -- not economically successful projects. One facility, even without subsidy, would have been economical with the actual rate it received, and this rate is actually a self-generation type of net metering program, so ultimately they ended up with about 10.3 cents for their power, and it cost them about 7.8 cents to generate it. They also used a significant amount of heat to offset propane cost, so that drove down their actual power cost, so that was a good project. And then I've got three in orange which I think are in the feasible realm, some of them had a little bit low capacity factor. If that bumped up, those costs would improve, but overall those are kind of in the realm of what you might be able to do for a new dairy digester project.

One other thing I wanted to add is the technology we work with at West Biofuels is a thermal conversion process, so it's similar to the bio gasification that happens in a digester, but we're taking solid biomass with a lower moisture content, converting it into gas, and then also converting it in a cogeneration unit. There's a potential with that technology to also ultimately go to liquid fuels. We think this is a technology that has fairly good competitive cost structure to it, but also can be implemented at food processing facilities, agricultural processing facilities, and we've focused on bringing that technology to California.

There's a working model in Europe, there's a number -- there's five of these plants with a technology that West Biofuels has been involved with, there's five of these plants in

Europe, and there's a number of other types of gasification systems in Europe that are functioning and this is just one example. And the reason I use this example is we're partnered up with the company that actually runs the plant, but also they've had a nice high number of hours of operation per year, and there's a lot of gasification systems that can't really claim that, so they have this nice operating history, able to get into higher sort of capacity factors.

This is my last slide. I did this Friday. It's trying to tackle this question of why SB 1122, why maybe some incentives from the EPIC Program, why does bioenergy need that. And I basically pulled this chart from solar buzz which talks about the price of solar PV over time, and the relationship between the market for PV and the price of PV, and I think this is illustrative -- I put the approximately amount of small bioenergy worldwide that's purchased every year, and it's been a pretty unstable market. Europe, of course, has been a leader in this area, but there's been fits and starts with programs to help incentivize small bioenergy. But relatively to where solar PV started, small bioenergy is looking pretty good in terms of its cost per watt, you know, at least according to this data, roughly where solar PV might have been in '06 to '07, and also with a much smaller market driving that price, so I think by creating a program that's stable, we can see -- and I can even see it out in the field as an engineer that there's great room for improvement in small bioenergy in terms of cost, but there has to be a market there to really drive that.

So, again, my nice little circle thing here and some contact information, and I think the whole panel is going to take questions now, but I'll hand it back to Garry. Thank you.

MR. MARISCAL: Thank you, Matt. So first, before I go on to my questions, I would like to open it up to the panel to see if they would like to respond to any of the presentations they heard. I'll start over with PG&E if you have anything? No? Anybody else?

MR. BOCCADORO: A question for other panelists?

MR. MARISCAL: Sure.

MR. BOCCADORO: And I'm not picking on PG&E, it just happened to be the utility sitting here today, so please don't take these comments any other way, there's lots of reasons to praise PG&E, in fact, those two projects in Kern County that we're awaiting the final approval from the Commission on, were negotiated bilaterally with PG&E; I failed to mention that in my presentation, but they're the only Investor-Owned Utility who has sat down and negotiated bilateral contracts with a dairy digester, probably the first and only two that will ever get done that way, but nonetheless, PG&E stepped up and we appreciate that.

I had a couple questions as related to your procurement figures and, again, I'm just asking this for purposes of illustration, there are three and if I can get them all out, I think you can answer them. How many of the 23 bioenergy contracts that are currently in your procurement portfolio are for new facilities, say, in the last five years? How many FIT contracts have there been issued under the Feed-in Tariff Program in California for bioenergy? And how many RAM contracts have been issued for bioenergy in California?

MS. KHAMOU: In RPS, let me take a look,

when you say "new," you said the last five years?

MR. BOCCADORO: In the last five years.

MS. KHAMOU: About 20.

MR. BOCCADORO: For new projects or new -- those are new contracts, but not necessarily new projects, correct?

MS. KHAMOU: Well, COD 2010, so this was within the last five years.

MR. BOCCADORO: Okay --

MS. KHAMOU: I mean, I could go back to 2008, there's about, if I do my math right, 22 if you go back to 2008. And in the Feed-in Tariff Program, we've had -- some of the new ones have included the one with Phoenix Energy. The RAM, we've had a geothermal facility come through RAM, but not a biomass one specifically, or a biogas one; however, we are holding, like I said, our fourth RAM solicitation currently, and we will be adding a fifth RAM solicitation one year from now.

MR. BOCCODORO: Thank you.

MR. MARISCAL: Any other questions or comments from the panel? I have a couple of questions. I'm going to start with PG&E, not to pick on you.

MS. KHAMOU: That's why we're here.

MR. MARISCAL: This is actually just a comment or a question for the panel based on one of PG&E's slides. PG&E noted the CAISO 2020 load projection, or however you want to call that. My question to the panel is, can bioenergy projects feasibly be designed to ramp up or down, or follow the load intraday as the CAISO has showed in 2020 to make these projects more attractive to utilities, let's say? So can there be an onsite storage system for a few hours and then a larger generator installed on the facility, basically?

MR. TORNATORE: I'll take a shot at that. It, of course, depends on doing the pro forma on the actual dollars and stuff, but with a gasification system, you can ramp those up and down, you can't store it, you can't store the gas, but you can ramp up your input into the gasifier; as a matter of fact, that's done now to follow when the prices are better during the day.

MR. BOCCADORO: And I think the same thing is true of dairy biogas. We've been looking extensively at developing units that could even be peak power loaded if that's what the utility wanted, but to the degree they need to be dispatched, we do have some flexibility, particularly -- we've covered lagoon digesters to have a natural storage avenue for dairy biogas.

MR. SUMMERS: Yeah, I would agree with that. Some of the systems that we looked at out in the field had days worth of gas storage under the cover of a digester, especially the covered lagoons, so they could probably serve that purpose.

MR. MARISCAL: This one is for TSS Consulting, for Fred. You mentioned something about delays in the permitting process. Do you have any specific delays that you had, agencies? Or is it local permitting that's causing the delays? Or is there some sort of State level permitting?

MR. TORNATORE: Again, I don't know if I said "delays," but the CEQA process does slow things up, and generally that's going to be through the local land use planning agency, whatever that might be. I found that, on the air side, because these projects are small, and we're proposing gasification with state-of-the-art general combustion engines for generation, is that we're falling under their thresholds, particularly at the one megawatt range, and even the two megawatt range, we're falling under their basic thresholds, so they're not the issue, just pushing things through CEQA. But, again, as I said, I don't have a problem with CEQA, you have to plan for it properly, and you just also have to find the money to do that work.

MR. MARISCAL: Do you think there's some amount of local education or outreach that can be done that might speed up the process, like more information about the technologies being available, that type of thing?

MR. TORNATORE: Well, we normally do that in our projects. We spend a lot of time with the stakeholders, all sides, all the way through from the local people through environmental groups, and the local agencies, and we do attempt to educate them the best we can. But again, in many of the rural areas where we're working for forest biomasses, you know, economic development, getting people back into work, getting some of these industrial old sawmill sites back into productive use, they're already in favor of it, it's just that they've got a process they have to go through.

MR. MARISCAL: Thanks. Any other responses from the panel? Okay, that's actually the questions that I had. If there are no other questions from the panel, I'll open it up to the audience. No? Stakeholders? Michael and then Pat.

MR. THEROUX: Michael Theroux, JDMT. Starting perhaps with Karen, when you look at your map and you think about the rural areas that PG&E covers, you do cover most of the major mountainous rural areas in California, not all, but most. When we try to look, as Fred and TSS has done, as the Forest Service is doing, at how to implement small scale bioenergy for these areas, whether it's fuels or electricity or product, or whatever, it becomes a community stewardship question, and it's dispersed. It's quite dispersed. The question that I'm driving at has to do more, not so much with your pricing, but with your infrastructure and where it stands and your perspective on multiple small facility network development through time in the more rural areas; in other words, fit the insertion points, if you will, into the locational sourcing. The less you have to carry of the stuff the better off you are, and the more energy dense you can make it at its source location the better off you are. Now, if energy density comes to creation of electricity at the point of CHP, then we have a mapping question in a sense: can we get into a programmatic EIR or a regional EIR that matches up with the stewardship issues and model with PG&E on those rural areas a pattern of multiple insertion points as one project? Now, with the shift to shorter scheduling periods that CAISO has just done, just in the last week, I think, to shorter periods, it may help us on the scheduling, but that doesn't necessarily help us with the insertion points into the smaller distribution lines. So could you speak to your current status and perhaps your modeling as to how the utility will work with the more rural and the more multiple facilities and multiple insertions like that?

MS. KHAMOU: Well, I know that our Electric Transmission group is working with the CPUC and the CAISO on trying to streamline our process a little bit more. We have the FERC jurisdictional and CAISO jurisdictional WDT, and then you have the CPUC jurisdictional Rule 21.

And so people have provided a lot of input, and there's a proceeding happening at the CPUC on Rule 21, and we've essentially melded the queues together so we're managing them as one queue, and trying to align some of the fees and study processes that happen. But there is a cluster process, you know, there are different studies that the various technologies trigger, and those are the requirements that we have to work on for grid reliability. So we're happy to work with folks and we've added additional staff to try and streamline this as much as possible.

MR. HOLLEY: Good afternoon. Pat Holley with California Biomass Energy Alliance. Just a question relating back to your chart, your CAISO chart, again, and I understand a request could be made of the existing biomass power facilities to cycle, or to transition to lower loads at certain times of day, but has there been any thought given to rate structures which would incentivize either wind and solar to change their profiles, or be compensated in terms of rate structure one way or the other?

MS. KHAMOU: Well, that would need to be essentially taken up with the CPUC, given we procure under the rules that they provide us and the TOD factors that we have to work under.

MR. HOLLEY: Yeah, I understand. One of the issues that we face in our industry is most of these facilities were built for baseload delivery --

MS. KHAMOU: Right.

MR. HOLLEY: -- so it's a challenge and there's economic penalties, efficiency penalties when we turn the plant down or throttle it up. So just a question. Thank you.

MR. MARISCAL: Thank you, Pat. Any other comments from the panel? Kim Carr.

MS. CARR: Hello, good afternoon. So I just wanted to bring up the point of pricing. Michael, you really laid it out as far as the intent of 1122. It inherently recognizes that this type of energy costs more, but yet there's these multiple benefits that aren't necessarily accounted for. And then, Karen, your last question was, well, who is going to pay for it? And I'm wondering, you know, to the full panel, what are your views on that? Because we know it's going to cost more, but who pays? And how do we reconcile that? And then what can we do within the policy framework?

MR. BOCCADORO: I'd be happy to take a stab at it. I think you hit the nail on the head. I think, you know, what we've recognized with bioenergy is it does not fit well trying to compete with other renewable technologies in either the RAM or the Feed-in Tariff Programs, and I think Karen's numbers bear that out. I don't want to misstate it, but you've had no projects, no bioenergy projects in the RAM program, and one bioenergy project, maybe two, I think there's a dairy that's under the Feed-in Tariff, it's an existing project, that have qualified under the existing Feed-in Tariff programs. And that's the real issue. You know, these other technologies, wind and solar in particular, are highly subsidized, have been for years, we've brought the costs of those technologies down, and that's a great thing, I'm not struggling with that at all. Bioenergy is now being asked to compete with these highly subsidized longer term technologies. So the whole point of 1122 was to say let's let bioenergy compete in a program designed for bioenergy. And we want some competition in that, we want the lowest cost projects, we want to get good broad cross sections of the different types, which is why the Legislature laid out three categories and multiple different types within each of those categories, so who pays? I think that's the key question. And whether it's Ratepayers or taxpayers, I mean, taxpayers are clearly paying for some of the subsidies that go to wind and solar, so are Ratepayers through some of the solar initiatives and other programs that are out there, and so we don't view 1122 much differently, and I don't as a Ratepayer advocate -- I've been representing Ratepayers before the Public Utilities Commission for over 20 years -- I don't separate in my mind Ratepayers and taxpayers, and I don't think we really should, and I'm comfortable whether or not those societal costs are being in some way paid for by taxpayers through some of the programs like Cap-and-Trade and others, and I'm perfectly comfortable with some of those benefits being paid by ratepayers. And I think ultimately the public is, too, if they fully understood the equations. I think the policymakers got it last year when they approved 1122. We had the blessing of having one of the best authors that we could possibly get in Senator Michael Rubio, who has now moved on out of the Legislature, unfortunately, but he really was able to articulate to his colleagues the societal benefits and the fact that, in the short term, at least, we're going to have to subsidize these projects -- not a lot, they're going to be above market, they don't have to be 30 or 40 cents like we saw early on with solar, but they're probably going to be somewhat north of 15 cents a kilowatt hour and are going to require some ratepayer subsidy.

You know, I think one of the real interesting points, and while the Utility Reform Network did not support SB 1122, notably they did not oppose it, they were very aware of it, and they did not come out in opposition to it because I think they recognize that this is a good arena for policymakers to be treading, and trying to create markets for these historical waste products that the state has. We live in a large state with a lot of waste from the dairy industry, from urban residents, from urban wastewater, from forestry to the agricultural residues; there's something we can do with that productively. And 1122, I think, is hoping to capture that. So I'm comfortable, you know, with the societal benefits being paid by society, whether that's through tax dollars or through ratepayer dollars, I don't think there's a huge difference from a policy standpoint.

MS. KHAMOU: Just a comment on that. So we've had actually eight Feed-in Tariff programs that are bioenergy related that have come through since 2009, I'm not sure what it is for the other utilities. But we do see -- when the Legislature passed the bills, and as they passed SB 21X, there's a cost containment mechanism that they also want the CPUC to work on, so that's actually slated by Commissioner Ferron this year for the Commissions, for the CPUC to start working on. In addition, when the Legislature passed 1122, they also put in the Feed-in Tariff the Section 399.2 and also asked it to be market-based. So we do think that the Legislature is supportive of this, but they're also supportive of containing costs for our customers.

MR. MARISCAL: Any other comments from the panel? Are there any other questions from stakeholders? Anything from the Web?

MR. TANG: So we had one question for Matthew Coldwell. This question is for Mr. Fred Tornatore: "Can he speak to the wide range of CEQA costs? In other words, what CEQA-related costs cause such a widespread uncertainty in the total CEQA costs?"

MR. TORNATORE: So what the costs were?

MR. TANG: So what they say creates the widespread -- wide range of costs?

MR. TORNATORE: Oh, oh, oh, yeah. We had quite a large range there, and I didn't really go into great detail about that, but basically as it goes through the process, the CEQA process, those have become something like a Negative Declaration, or a Mitigated Negative Declaration, which can be -- which is a much shorter and less expensive process than going to a full Environmental Impact Report. That's really the range of costs there, is going from a Neg Dec to a full and very detailed Environmental Impact Report on perhaps a sensitive area.

MR. MARISCAL: Michael.

MR. THEROUX: Michael Theroux, JDMT again. You know, this is -- the question of CEQA that we keep stumbling over here are individual projects, yet the problem that we face is not one project at a time, especially as we work with the smaller systems, and I alluded to this a little bit here. The state has in other places initiated programmatic EIRs, for example, for the AD, and I think that it's a good point for us to consider that we're really looking at regional utilization in small amounts, and that's one program. Now, the forest service fortunately leads us in this nationally with the work that they've done for the new forest plan and the cooperative forest landscape restoration, and the overspill, so there are some programmatic EIR approaches, I think, that we need to take into account as we consider where to go with a Bioenergy Action Plan because one of the things that we keep hearing is, "My goodness, we can't handle $300,000 to a million dollars a pop like this for these little teeny projects." And in reality they're just one here, one here, one here, one here, in a regional network that may take time to implement. But once we have a programmatic EIR in place, it addresses many of the questions that folks like the Center for Biodiversity have regarding waste versus virgin material and staying away from things like forest mining and the difficult issues of stewardship, which is underlying most of this, stewardship of the entire set of resources that we're working with, and I think that applies for the forest, the Ag, and the urban, as well. So I would ask that, in the context that we're in today, to take a real hard look at initiating programmatic assessment in conjunction with and in parallel to the rulemakings at the CPUC, and try to push that issue through. It would allow us a tiering mechanism and answer an awful lot of the questions first, and then we could address the specifics of each project tiered off with that.

MR. MARISCAL: Thank you, Michael. Anybody from the panel?

MR. TORNATORE: I agree with Michael wholeheartedly. It would be a good way to go and it takes some time to do that, of course, but if we had a Programmatic EIR to where we could tier off of that on projects, particularly the ones that are going to happen, and maybe the two- to three- to four-year horizon, it would be very useful. And that's certainly one approach.

MR. MARISCAL: Thank you. Any other

questions, comments? Okay, I want to thank all the panelists, especially PG&E for being the only utility on this panel today, appreciate it. Thank you. [Applause] And before we head off to break, I just want to remind you that Pat Holley from the California Biomass Energy Alliance will be presenting right after the break, and then we will have our final panel session with Kim Carr, Peter Tittman, and Kevin Bundy. Thank you. We'll take a quick 10-minute break and we'll be back here at 2:45.

(Break at 2:35 p.m.)

(Reconvene at 2:53 p.m.)

MR. HOLLEY: That you for that rousing round of applause. Good afternoon, everyone. It's a pleasure to be here today. Again, my name is Pat Holley with the California Biomass Energy Alliance, and we're very glad to be here today to talk to you about the existing biomass industry, what we've done over the years, where we're at today, and what Boiler MACT holds for us, although that's a two-day seminar which I'll condense into five minutes.

So I'm currently General Manager of HL Power for Greenleaf Power here in California, and also fortunate enough to be the Chairman of the California Biomass Energy Alliance, and I get to represent people who have worked hard for the last 25 years generating renewable power around the clock for Californians.

This is the Trade Association of California's solid fuel biomass energy producers, collectively the industry generates 650 megawatts of baseload renewable power, as I say, that has been generating around the clock for 25 years.

Just to give you a snapshot of our industry, currently there are 34 solid fuel biomass facilities in 19 counties. In many counties, we're the largest taxpayer, largest employer, among the largest employers. There are four facilities currently idle, one new coming on line in the fall in Stockton. The two facilities that have come on line in the last year will consume approximately 500,000 tons of wood fuel, so we're a large scale industry that produces 12 percent of the Utilities' -- the IOUs' renewable power in California.

We use -- we have a typo on this slide here that you see, luckily it's so small that most of you that are near my age probably can't read it, but it should say approximately five million tons of solid waste residue. This is residue from logging operations, landfill diversion; this is all of the wood waste from the forest and the agricultural facilities around the state that we utilize for biomass energy generation.

Forty thousand acres of forestland were treated in California as a result of the market for biomass. Biomass helps local governments meet landfill reduction mandates by diverting a total of 3.5 million tons annually.

We've helped local Air Districts comply with Federal Air Quality Standards by reducing emissions of criteria pollutants and preventing open burning of agricultural waste and forestry residues. If we were not in place, we would be emitting into the atmosphere hundreds of thousands of tons of particulates and carbon monoxide. Our facilities operate with emissions controls and a controlled environment to produce electricity. California has an abundance of biomass residues, although I do remember from a prior slide that there was a projection that there might be 14 million tons available of forest residue, and that's a stretch, that's a big big number given the constraints that we operate under. Everything that comes into our facilities is a result of a permitted, certified logging operation that results in the residues that come into our plants, so ramping that up to get to 14 million tons annually is a very heavy lift.

Here is a graph that shows our fuel markets. In the blue, you see approximately a million and a half tons of mill residue, this is coming from sawmills; again, this material is coming from approved logging operations. The yellow chart that you see is our urban residue, this is landfill diversion where we help our partners in county and local government meet their diversion requirements. Our facilities take this valuable wood product and make electricity. The red chart you see is agricultural residue, our farming and agricultural community in California generates a tremendous amount of waste from orchard removals and pruning operations, which 30 years ago were open burned, so all of that pollution was emitted into the atmosphere of California. Our facilities in the valley help avoid that pollution that would have occurred as a result of open burning. The green in the front of that chart is the in forest residue. This is wood waste slash and treetops from approved logging operations, again.

Some challenges in our industry which we work through. We've been around a long time and our industry is very active and works with stakeholders on our challenges. Most of the existing industry comes from the QF movement of the 1980's, so we have short-term prices in the current contract environment that lead us to a new renegotiation point, beginning as soon as this year. And we have expiring Power Purchase Agreements, long term agreements, most of them were 30 years, you know, dating back to the late 1980's, so they're coming up on expiration, which means we're at risk now in this new lower energy pricing environment. These facilities can be at risk because of these low power prices, and I might add, that's a bit of a distortion caused by low natural gas prices right now. Of course, low natural gas prices are good in many ways, but they don't help in this current contracting environment where a utility evaluates a bid, and then compares to their SRAC pricing of approximately $40.00 per megawatt, or four cents per kilowatt. There are environmental societal benefits that need to be recognized and paid for and in many cases, many of our attributes are not truly compensated for, and we want to continue to work to change that.

And so in order to do that, some of the things that are very helpful in the 2012 Bioenergy Action Plan include several recommendations that would be of great benefit to our industry, 1) the CEC in cooperation with the PUC could conduct research necessary that would allow contracting utilities to fully value the electrical asset that we provide and include reliability, schedule ability, voltage support to the grid in many cases, and environmental attributes, reduction of open burning, all of these benefits that biomass energy provides.

And we also, in this Bioenergy Action Plan, another item that's very important to us is the mention of a biomass fuel offset protocol. This would assist the industry in monetizing our attribute of biomass carbon footprint.

The appropriate AB 32 Cap-and-Trade auction revenue for targeted biomass fuels program, we believe that there is much more fuel out there that we can get at, but it's not always easy to get. We are looking for reasonable incentives to help do that, to gain these fuels that would otherwise be open burned.

We're going to continue to work on the U.S. EPA's Non-Hazardous Secondary Materials Rule and the Boiler MACT Rule, which is now in the implementation phase, I'll talk more about that in just a minute. The EPA Non-Hazardous Secondary Materials Rule has to do with how we classify facilities vis a vis their utilization of various types of biomass wood fuel.

And we also have on our radar screen the U.S. EPA's Tailoring Rule and its application to biogenic greenhouse gas emissions. This is very important to our industry because we believe we're part of the solution to climate change and global warming. We believe that our industry has a very nice story to tell.

Moving on to the Boiler MACT, EPA issued a final rule for major sources on January 31st of this year. Major sources are those who emit more than 10 tons of a hazardous air pollutant, or 25 tons in total of a list of these hazardous air pollutants. Our industry worked very closely with U.S. EPA, California ARB, the Air Districts, and CAPCOA, that's the California Air Pollution Control Officers Association, in providing comments to EPA, which greatly improve this Boiler MACT rule. There were some very adverse points in that which CAPCOA pointed out with great eloquence, and I left a copy of that on the table out front. It really shows you what CAPCOA was thinking in terms of the Boiler MACT rule and its potential negative impact on our industry. They view our industry as essential to maintaining Air Quality Standards in California. They also noted in that CAPCOA letter that biomass energy plants operate under strict emissions limits and are backed. Most of the plants in California are controlling NO_x using selective non-catalytic NO_x reduction, that's ammonia injection, which most of our facilities are engaged in. And that was a big concern in the Boiler MACT Rule because EPA's concern was emissions of CO, and there's a direct relationship between CO and NO_x. In California, our priority is NO_x because of smog and ozone. So California, the CAPCOA organization submitted comments to EPA along those lines.

CAPCOA also noted that several facilities may be determined to be major sources as defined under the Boiler MACT Rule for a couple of simple reasons, one includes irrigation methods that are used in the Central Valley that cause the accumulation of salts on orchard wood, orchard removal wood that would come to our plants. So a little bit of chloride that comes from the agricultural regions of California would find its way into our boiler and, upon testing, we would be found to emit more than 10 tons per year of HCL. So that became a very important point on the classification of our biomass facilities. The other difficulty that would create is if you open up your permit to make changes, or to modify using reagents, you could reopen your permit and find yourself reopening a Federal PSD permit, which is very difficult to open and difficult to change, and you have to go through Region 9 EPA here in California, to do that.

The other key part about Boiler MACT,

the last item on this slide talks about the NHSM Rule, Non-Hazardous Secondary Materials. It was EPA's way of classifying biomass in our case, using a set of tests. And I could talk about those a little bit. Basically, those tests are can you meet a legitimacy criteria for determining that it's a wood product, or a traditional wood fuel, and in our case we've been using this fuel for 25 years, its landfill diversion, this is scrap wood coming from construction. It's sometimes called urban wood as you see in this slide here. In EPA parlance, they use the term C&D wood, so there's a little terminology here that's involved in how you look at this wood fuel.

But basically the rule issued earlier this year notes that C&D wood will be reconsidered, EPA believes that there are a lot of reasons for reconsidering it, and we'll continue to follow that process very closely. If the wood were determined to be a solid waste under this NHSM rule, you could conceivably have all of the facilities around the country brought into commercial and industrial solid waste incinerator rules, which would put them all out of business. It's very adverse to the industry. This is very important for two reasons, the avoidance of open burning, which our facilities accomplish here in California, and the second reason is landfill diversion goals established by the Legislature. If we were to lose the ability to divert wood waste from landfills, that wood would turn around and go back to landfill and generate methane, which would aggravate the greenhouse gas picture. So this is a really essential rulemaking and we'll follow this very closely as EPA gets ready to issue a proposed rule, so it will probably take them some months to do this.

I'd like to thank you today for your attention and leave you with a couple of closing remarks. I always like to leave people with a little bit of what we do and how we benefit the environment and our communities. And I would just say that our industry produces 12 percent of California's renewable energy in the state, and employs thousands of people in doing so. Our industry allows agricultural communities, the forest communities to avoid open burning, we reduce wildfire danger by doing so, and we also avoid the emissions of thousands of tons of CO and particulate matter into our air here in California. So with that, I'd like to thank you for your attention and would take any questions.

MR. MARISCAL: So are there any questions for Pat Holley? Comments? Going once. Thank you.

MR. HOLLEY: Thanks. I'd be glad to take them during the panel.

MR. MARISCAL: All right. Thank you, Pat Holley, for that great presentation. I'll now open it up to the panel. This panel is going to be talking to us about environmental considerations and the benefits of bioenergy. We're going to start with Kim Carr from Sierra Nevada Conservancy. Go ahead, Kim.

MS. CARR: Good afternoon. Thank you, Garry. So my agency, the Sierra Nevada Conservancy, we're a small agency within the Natural Resources Agency. The mission is very broad, it is basically balancing and improving the environmental, economic, and social well being of the entire Sierra Nevada Mountain Range.

This map shows the area we cover, which is essentially from the Oregon border down to about Bakersfield, the east side and the west side.

And the Sierra Nevada certainly is recognized as primary headwaters for the state, great recreational area, iconic locations like Yosemite National Park, Lake Tahoe, as well as forests, biodiversity, flora and fauna diversity and habitat, etc. So our mission is really about protecting the very essence of the Sierra, but also supporting the local communities that exist there because they're really key to sustainable resources.

So a couple of the key issues we've been targeting lately is that, you know, the majority of the area we're working within is forested and a lot of that is publicly managed, but also plenty of private management of forest, as well. One of the key issues is fire threat, the fact that wildfire continues to increase as far as severity and number of acres burning. The wildfire season is much longer, right now there's a 45 square mile fire burning in Southern California. So we're seeing that the season is starting earlier than it has in the past. So that's one issue is, how do we take this amazing resource and remove it from being such a threat, both economic and ecological, and really manage it a way where it's beneficial for multiple reasons?

Another issue completely related to that is trying to raise the funding to actually restore the ecological function of the forest so that it's more resilient to beetle bark infestation, increase in wildfires, particularly in the era of climate change. So we've been looking at this for a long time, long before the California Bioenergy Action Plan came along, and SB 1122, and seeing that a real benefit where you can meet these multiple benefits is thinning the forest in a way to restore the ecological health, but using that small diameter wood treetops, etc., locally, so whether it's light manufacturing, whether it's clean wood burning stoves in individual homes.

With the Bioenergy Action Plan coming along in 1122, it's put more focus on the energy component. This has already been outlined, but the Bioenergy Action Plan is really quite broad as far as multiple objectives it is meeting, calls out environmental and economical and sustainable energy, but also diversity of technologies, creating jobs, reducing fire damage, and improving air and water quality and reducing waste.

So our agency in particular, our task is the easy task, we're to work with communities to actually establish demonstration projects. This is actually a really challenging task and I think the panel brought forward a lot of issues as to why. So we're involved with helping to secure funding, to get the pre-project development occurring, coordinating multiple stakeholders, multiple interests, developing criteria so that we're hitting the right point, we're appropriately sizing and locating these facilities, and then also actually supporting communities to set these facilities up.

We went through the Senate Bill already. But really, I mean, again, a real important component of SB 1122 coming along is we didn't focus a lot on that as being an outlet for biomass, not the small scale ones, there have certainly been a lot of these facilities as co-generation usually associated with a timber mill, but we really weren't looking too closely at small scale, a lot of that is the economy of scale, until this came along.

One thing I want to point out is this is not the silver bullet, there is room for a lot of different uses for this small biomass, and we're going to continue to focus on that, looking at different clusters, campuses, multiple use, and multiple job opportunities. And I just want to point out here, it's a 50 megawatt target for the biomass sector. When we achieve that, it will support about 31,000 acres of biomass thinning per year. The Forest Service alone, just one public agency that manages the forest in this region, has estimated a need for 400,000 to 500,000 acres of restoration and treatment to occur per year, so that's more like six to nine million acres of biomass. So it's not going to get us there, we're going to continue to look for other opportunities for local biomass utilization.

So this is just forest -- the typical one is on your left, a lot of underbrush, a lot of fuel ladders, really a lack of diversity of age and species; to the right, this is after a thinning project, keeping the larger trees, and taking away the brush.

This map is the Sierra Nevada on the left, the Northern Sierra, the Southern Sierra on the right, the main point is that using biomass for electricity and heat has been a common practice, as I mentioned, generally associated with the timber industry and mill operations. Those are closing. It's been on the decline for a long time, and so in looking to small scale, appropriately distributed energy, it's good timing, and it seems like we should be able to reach some consensus where we can really move forward with this.

Now, a lot of the multiple environmental benefits associated with biomass energy is that the current most common practice with managing this waste after a forest treatment project is to pile and burn it, so multiple problems with that. And it's difficult to get an opening where you have the appropriate conditions to actually do a burn, so what you'll end up seeing is that these piles will sit for a number of years and become a fire hazard in and of themselves, where one of the primary purposes of the Forest Treatment Project was to reduce the fire risk.

So just a list of a few more advantages to what we're doing here. Certainly, the baseload for renewable energy, helping the state meet the distributed generation goals. I've talked about the need to have some kind of a revenue source so that we're actually able to treat enough acres per year, where we can start to actively reduce the risk of catastrophic fire, and then be able to enough mechanical removal of the very dense forest that we can allow for proscribed burning because there's multiple benefits to burning forests, but you need to do it under a condition where the fire is not going to get away from you.

Also, the greenhouse gas reduction -- in a lot of the rural area the primary fuel source is propane, so this is an opportunity to move people off of propane into a renewable source. It reduces waste from some of the materials that will be destined for landfills, reduces that. And there is certainly a net improvement in air quality. There is newer research showing that if you thin out some of the smaller brush and small diameter, you make room for the larger trees to grow, and that's where the real opportunity is to actually sequester carbon, so really supporting that, too, to improve the primary sink that we have in California to sequester the carbon.

Much of the headwaters for our water system is in the forests in this state, so really protecting that so we have some secure supply, certainly the water quality that we are conditioned to have. And finally, you know, California, it is our recreational base, so continuing to protect our forested areas.

So I just want to show you this. In Placer County, their facility -- they're really the first ones to move forward with a facility, it's two megawatts, their Air District Control agency had this work done where the orange is comparing when you pile and burn biomass, the other side is comparing emissions associated with shipping the biomass, transporting it, and then burning it in a boiler. And you can see that, for those four key air constituents or air pollutants, it's substantially less.

The Biomass Working Group has been mentioned earlier, this is a diverse group of stakeholders and we've been meeting monthly going on a few years now. This group has been really key in crafting some of the language for the Action Plan, and then also working through the multiple challenges we have with really implementing this.

And then I just want to show you, you know, I asked the question earlier about pricing. And I think with the Black & Veatch report there were some of these issues highlighted, but I think there's room to do a lot more of this.

This map, again, is the CAL FIRE map that shows moderate, high and very high first risk, yellow is moderate and, then, as you get darker into the reds, high fire risk. If you look a little bit closer, you can see the light green lines running east-west across these high fire risk areas, particularly on the right side of the map. These are transmission lines, so these transmission lines are running immediately through these high fire risk areas. A colleague of mine pulled out the Catastrophic Event Management Accounts from the CPUC and estimated that $285 million of rate increases have already been approved, and the primary cause and the need for those rate increases was wildfire costs and bark beetle fire prevention, a lot of these being in Southern California with the numerous fires. So these fires cost a lot, they're a direct cost to the utilities, and in particular there are transmission lines running through these areas, as well as other operations.

So finally, sustainable forest biomass, another key area called out in that Action Plan, we're working closely with CAL FIRE and starting to pull together a group of diverse stakeholders looking at the issue of establishing sustainability standards because none of us want to overdo this or overshoot the right balance between appropriately locating these in the high fire risk areas where there's abundant fuels available and sizing them appropriately. We don't want to create an over demand for the forest, we want to continue to manage the forest while we're improving the ecological conditions, and only using the waste product within these bioenergy facilities. And this is also called out in SB 1122, as well as 1504.

An then just an example, I mentioned earlier Placer County really does have the first one, but it's not really an 1122 facility because it's not in an IOU service area. It's two megawatts; their Board just approved the Conditional Use Permit and adopted the environmental document, and there was an appeal regarding the permit, as well as the environmental document. Fortunately, the County and the Center for Biological Diversity were able to work out conditions, particularly around fuel sourcing and around some of the management in order to encourage the Center to withdraw the appeal and move forward with the permitting.

So we've had some issues already come up, but I'm very hopeful that a precedent has been set where negotiations can occur and conditions can be made and placed so that all entities feel comfortable with it and the facilities can be permitted. So that's all I have. Thank you very much.

MR. MARISCAL: Thank you, Kim. The next presentation is going to be from Peter Tittman.

MR. TITTMAN: Good afternoon, everyone. Thanks, Garry, for the invitation to come and speak today. My name is Peter Tittman, I'm at the University of California at Berkeley in the Center for Forestry. I'm in a program there that works on technology, marketing, and environmental impacts of using biomass from forest residues as an energy product, that's both fuels and electricity. I'm going to talk today -- Garry and I might have got our lines crossed a little bit, but I'm going to talk a little bit about feasibility, some technical issues with feasibility, and then also try to address some of the issues about impacts. I tried to shy away from the term "sustainability" because I think it's kind of vague, and I'll go into that a little bit, but some of the important impacts, I think, that have been brought up around bioenergy.

So technical feasibility. I'm going to talk a little bit about resource availability and cost, and some of this is stuff that you've already seen, but I think it's an important aspect in thinking about technical feasibility resource competition between biofuels and electricity, the evolution of technologies for converting the material into useable energy products. And then I'll talk a little bit about some issues related to, for lack of a better term, sustainability, particularly greenhouse gas emissions and forest practices.

With regard to technical feasibility, I think -- and this has been emphasized throughout the day -- I think that one of the most important aspects of technical -- of feasibility of bioenergy is a market, and return on investment is probably one of the most important drivers for technical feasibility. And this is sort of -- I tried to exemplify this here by -- these are projected imports of pelletized biomass, wood biomass, into the European Union over the next, well, a 10-year projection to 2020. And this is the demand for wood pellets in EU has gone through the roof, and this is because there is a significant subsidy that the UK and other European countries have put on the value of producing this renewable energy, that $99.00 per megawatt hour, that's on top of the value of that electricity in the marketplace.

So give a market to any of these technologies and they'll grow, and not only will -- well, I'll get into some of the effects of the long term effects of markets on these technologies in a second, but I wanted to go over really quickly this data comes from the California Biomass Collaborative. This is a supply curve on the bottom axis, you see dollars per ton, willingness to pay for these feedstocks, and on the vertical axis it shows the potential tons per year that you could get with a willingness to pay of these various different prices. And you can see a pretty substantial amount of resource, most of it in, as we know, forest and municipal solid waste, and some Ag residues. And importantly, this data doesn't include things like manures, biosolids, wastewater, and previously landfilled residues. So at a full utilization of the solid fuel component of this -- and unfortunately it's cut off there -- but we could get up to around 4,000 megawatts of production.

One of the challenges with resource estimation in general is that, especially with regard to the forest residues, that it's very difficult to do and do accurately. This is three different estimates from California Department -- well, CAL FIRE in the red, the Forest Products Lab, that's USDA Forest Service, they have two estimates, one that includes and one that doesn't include public lands. So you can see there's a wide -- basically the vertical axis is the bone-dry tons per year of potential supply in these various counties, and there's a wide range of estimates as to what is potentially available from the forest residues in California.

Let's see if there was anything else I was going to cover -- yeah, it's very difficult to get a sense of what the actual technically available resource is, and my point here really is just that maybe that's not the most important aspect of sort of looking at the feasibility of bioenergy, and I'll get into that a little more in a moment.

But this is another component of understanding the supply and availability of forest residue, these are procurement costs for biomass from forests. You see on the horizontal axis is a diameter breast height and the vertical would be the costs, and the different colors represent the different components of a harvesting and transport operation. The top is a 10 percent slope, the bottom left is 30 percent, and the bottom right is 60 percent. So you can see there is a huge range in what these feedstocks cost delivered, and the assumption here is a 100-mile haul distance.

Another issue that I wanted to point out here, and others have mentioned it today, is this issue of the ancillary benefits related with utilizing forest residues for electricity. And this comes from an NREL report that Gregg Morris did as a consultant back in 1999, and he estimates about 11.4 cents per kilowatt hour of purely ancillary social benefit to using wood residues for electricity, and that includes avoidance of criteria pollutants, greenhouse gas mitigation, avoided landfilling, timber stand improvement, and importantly, it doesn’t include things like wildfire suppression costs that would be avoided under utilization regimes, impacts to utility infrastructures, as Kim mentioned, water delivery impacts which there's some interesting work going on at Berkeley about the effects of forest treatment on water delivery, and just the baseline market price for electricity. So if anybody, knowing what the market rate for electricity is right now, we can sort of very clearly see that there is kind of an under valuation of this energy resource to society. And good points today about who should bear that cost.

Unfortunately, this slide is a little difficult to see, but this is some work I did at Davis with my colleague, Nathan Parker, who was here this morning, looking at the competition for feedstocks between electricity and biofuels under different market prices for fuel. And the point really here is that, without a market for low carbon biofuels, the electricity sector can sort of suck up as much residue as they can afford. Once a price is -- once low carbon biofuels are valued in the transportation fuel market, those technologies have a much higher ability to pay for the residue, and therefore a lot of it will likely go into fuel production purely based on the differential in the value per joule of energy in fuel versus that in electricity.

I made a cursory point a moment ago about the effect of markets on technology, and this is just an illustrative graph of the progression in costs of the electricity production from coal over a period of time in Japan and the United States. The point here really is that, if we want costs of electricity to come down, if we're concerned about the Ratepayer at the other end of some of these what now are early stage technologies, I think one strategy and a strategy that has been employed in various degrees through the Energy Commission and the PUC is to sort of piecemeal research and early stage funding together, but I think fundamentally what will end up driving the economics and the evolution of this technology into something that's more efficient and actually competes is a sustained market signal; without that, I think we're going to be coming up with a lot -- we're going to still see figures like the ones that Michael spoke of earlier where you have a lot of projects that get funding, but don't actually deliver the benefits that, you know, maybe they were intended to simply because that market signal is so fickle.

So just a general summary of this feasibility component, I think a lot of it is directly related to markets. Markets will drive the innovation and feasibility of bioenergy projects, whether it be biogas, whether it be forest-based biomass, any of these things, as long as there's a clear market signal, capital will move to those sectors and you'll see innovation and you'll see production prices come down.

The resource's potential is a constraint, but it's difficult to quantify and it's unlikely to be a limiting factor on balance with procurement costs. And, again, a sustained market will exert downward pressure on production costs. And as we've seen many times today already, the cost for these pre-commercial technologies or early stage technologies, are often very difficult to justify on a purely economic basis. But over time, I think we'll see those costs come down given a clear signal.

And monetizing these ancillary benefits, that Kim has talked about and I pointed out earlier, can be a way to kind of bridge that gap between where we are now with these technologies into kind of a more sustainable and really economically justified context for bioenergy.

As an academic, I had to sort of be a little pedantic here, and I apologize for being pedantic late in the day, but this term "sustainability," I think, David Harvey is a very well respected geographer and he makes some really excellent points here, I'm not going to read it verbatim, but basically the point here is that when we use this term, it's kind of a cop-out in a lot of ways. Essentially, what we need to do when we speak about sustainability is to be more specific and say what we actually mean, what are we actually measuring? What are the specific criteria we'd like to see? What does "sustainability" actually mean? And, as well, it's too passive or static, it basically assumes that there's sort of this nice balance to things in the universe and that we should be looking to achieve this balance when, really, the universe is a lot more dynamic, and we need to kind of take an active role in defining how we want our relationship with nature going forward.

So I apologize for that brief philosophical digression, but what I think we talk about when we talk about sustainability in this context is forest productivity, forest resilience and resistance to climate change and wildfire, habitat presentation and greenhouse gas emissions, water quality and quantity, ecosystem services, jobs, environmental quality, and the list really goes on, and I think -- I'm not going to try to tackle all of these, certainly, but I think it's important to use these terms to speak about the things that we actually value as opposed to kind of this nebulous term.

And it's really late in the day for a chart like this, and I apologize, but this is a schematic of kind of the industrial ecology of forest products. At the bottom you have harvested biomass, that could be logs, that could be residues from fire hazard reduction operations, and then moving up you see the utilization pathways -- wood processing, energy, pulp and paper. The important point to emphasize here are these relationships between products that are a result of this forest product supply chain and products that are in the marketplace outside of that supply chain, that these products compete with, that's electricity, wood products in competition with other types of building materials, concrete and steel in particular, biofuels; these forest products don't operate in isolation in the marketplace, they actually displace other materials in these sectors, and I think that's an important point to keep in mind when we think about the impact of utilizing forest residues for energy, for wood products.

This chart is not my work, but I think it brings to light a good point. What you see on the left is a number of scenarios characterizing greenhouse gas emissions from utilizing pelleted wood from standing trees and wood residues, co-firing with coal, the horizontal access is time, the vertical is the aggregate emissions, and the line to pay attention to is the dark black line which shows the emissions over time. And in the Scenario A, which is utilization of wood residues from harvesting operations and co-firing with coal, there's been a lot of discussion about this issue of a carbon debt which basically says if you use this residue from forests, there is a temporal -- in the early stage, there is an increase in greenhouse gas emissions regardless of the over time impact of sequestration in the stand, kind of questioning the assumption that all biomass is carbon neutral, and it's a good exercise, but I think the data actually shows that, yes, you do have a momentary injection of greenhouse gases into the atmosphere, but over time the aggregate diminishes really significantly and, importantly, in this discussion about carbon debt you have an important distinction between old -- what some people call old and new carbon -- basically carbon that comes from a biogenic process that is within a geologic timeframe that we can operate in, that's forests that grow and regenerate, versus greenhouse gases that come from fossil sources that, really, that's a one-way pathway from geologic storage into the atmosphere, whereas the other kind of new carbon is already part of a biochemical carbon cycle.

So I think there's a lot of concern about the impact of forest bioenergy on utilization of forest residues for bioenergy on forest practices, and I think while it's important to keep that in mind, I think it's really unlikely that markets for biomass will really incentivize an additional adverse impact on forestry operations. I think the market signal is really -- the high value for forest operations is in timber and those, you know, I just don't think you're going to get the value proposition for industrial timberland that will cause them to significantly change their operations. And restricting or reducing the use of forest residuals will likely -- again, won't likely impact industrial timber operations, which are mostly driven by timber value in the Forest Practice Rules. Also, and this is an important low hanging fruit for low carbon energy source, and this is an opportunity as Kim was mentioning earlier to enable really a restorative forest management on public lands, private lands, that generate little or no timber value.

So that's the end of my spiel here. I'd like to thank John Shelly who is my supervisor at U.C. Berkeley, Center for Forestry, and my work is funded in part through a cooperative agreement with the Forest Service. And with that, I'll turn it over to Kevin and then we can take questions later.

MR. MARISCAL: Thank you, Peter.

MR. BUNDY: Thanks. My name if Kevin Bundy. I'm with the Center for Biological Diversity in our San Francisco office. And if falls to me to give the minority report today, I think. But I really do want to thank the Commission staff for reaching out to us and asking us to be here today.

I think there are a lot of different conversations that are going on all at once when we talk about forest bioenergy. We're talking about greenhouse gas emissions, we're talking about renewable electricity generation, we're talking about the relationship between forests and fire, and we're talking about the ecology of the Seven Cascades in the Sierra Nevada, especially. And sometimes those conversations seem to all take place in different rooms, among different groups of people, and I think this is an important opportunity to kind of start bringing some of those different conversations together because these things are very tightly interwoven, and you can make a real mistake if you push policy in one direction for certain reasons without thinking through what some of the unintended consequences might be. So I'm going to talk about some of those.

This is pretty much what everyone here is already familiar with, the assumption of the benefits of bioenergy, reduction of greenhouse gas emissions, the reduction of air pollution from open burning, as well as reduction of emissions from wildfire and the idea that if we build enough of an energy infrastructure for generation of electricity from wood that we can actually change the economics of thinning projects and get more thinning and restoration projects done out in the woods to achieve sort of land management goals, and thereby reduce the risk of what is thought of as catastrophic fire.

And these are the benefits that I think folks are talking about wanting to monetize and try to assign a value for in order to deal with the costs of bioenergy that I think are the most common ones that we all think about and talk about, which is basically the cost of electricity, the cost of harvest and transportation, the factors that make forest bioenergy cost $.15 a kilowatt hour, $.20 a kilowatt hour, depending on where it is, as the Black & Veatch report quantified. So this idea is that, I mean, if we can just quantify the benefits, maybe we can offset those costs, but that's really just -- offsetting those costs is really just another way of saying "find a policy justification for the subsidies necessary to create a market that the market itself is not creating because of the expense." And I think that's been clear throughout the presentations today. So I just put a different spin on it.

I have a little bit different view of the carbon debt issue than Peter did, and I'll talk about that. I also want to get into some of the fundamental assumptions around forests and fire and thinning and the role of that. I really appreciated that the David Harvey quote on sustainability, I think it's a really important direction, not to just throw that word about, but to actually unpack what do you mean. And then a couple at the end, looking at the air quality and public health impacts, and also the water use and wastewater disposal associated with these facilities. And I'm going to focus a little bit on the SB 1122 type of facility, a smaller gasification facility with an IC engine, you know, one, two megawatts, because I think that's sort of the thing that's on the table.

This is something that is just, it's basic, but I think it needs to be said at the beginning of this discussion, that when you measure it at the stack, biomass combustion produces a lot more CO_2 than coal or gas because wood is less energy dense and combustion is not all that efficient, I mean, unless you're doing combined heat and power application, you're looking at efficiencies in the 20's -- 20 percentile range, generally.

This is a slide from Mary Booth at the Partnership for Policy Integrity, who has reviewed dozens and dozens of actual permits, air permits for biomass facilities, and has gathered information from that. She also has used field content, heat content data from EIA. And this is a steam turbine, I believe these are stoker boiler figures, but you can see the biomass, you know, just in pounds of CO_2 per megawatt hour, and that's quite a bit more than the fossil fuels. This is not an argument for fossil fuels, this is just a starting point for what we're dealing with in the greenhouse gas analysis.

So if biomass is to have a greenhouse gas benefit, it doesn't come from displacing fossil fuels, alone, it has to come from somewhere else in the biomass lifecycle because biomass actually starts out behind fossil fuels in terms of CO_2 per megawatt hour. That's also -- I wanted to check and just see, looking at one plant, is that also the case with gasification? And just using the numbers from the EIR for the Cabin Creek facility in Placer County that Kim talked about, you know, it's up there above 3,000 pounds. And this is CO_2 equivalent, the way they ran the numbers it didn't break out CO_2 from the methane and the NO_x SO_x side, but that is mostly CO_2, the difference in the emissions factors for CO_2 and the CO_2e is not that great, less than a kilogram per MMBtu. So it's still a high CO_2 way to generate electricity.

This is essentially just a slide about the carbon problem, I think Peter actually articulated what happens. I mean, you cannot assume anymore that biomass is climate neutral or carbon neutral, there's been a lot of recent science, a lot of published scientific articles in the last eight or 10 years, especially, we're really going back to the mid-'90s, that kind of cut against this assumption that because CO_2 is biogenic, it somehow behaves differently in the atmosphere than fossil CO_2. Infrared radiation cannot tell the difference, and CO_2 has a long residence time in the atmosphere regardless of where it comes from. So, again, there's nothing magical about biogenic CO_2, it's CO_2.

So in order to figure out what the lifecycle implications are, a lot of people are kind of looking at comparing what happens with biomass combustion to what would have happened otherwise, and I think that's implicit in some of the work that has been discussed. And there is just a wide range of assumptions that are brought to bear on that question. And there's a really interesting article, a Bart Holtsmark article from late 2012 or earlier this year, that did a literature review and kind of teased out, well, what assumptions do you bring to this analysis and what do you end up with? And if you replace those assumptions with more realistic assumptions, what does it do to your analysis? Again, I mean, not just sustainability that we should be specific about, but the assumptions that we bring to this analysis, as well.

But there is a period -- because biomass produces more CO_2 than fossil fuels from the stack per megawatt hour, you do have this period during which your lifecycle has to catch up, whether it's through decomposition, the alternative fate of decomposition, or through re-growth of the biomass, that can be decades to centuries. And that figure has held across a number of different ecosystems, a number of different regions. And I apologize, this slide is hard to read, but the timing of emissions matters, the carbon debt actually does matter, because there's a short term increase in CO_2 emissions.

These are pathways that were pulled together by climate scientists working for the UN environment program. We're trying to figure out what emissions reduction pathways are actually likely to get us to a two degree warming scenario by the end of the century, and they did some pathways that actually take into account economic feasibility, and then some stylized pathways. They're just, "Well, what if we reduced emissions by this much or that much?" So I like to pay attention more to the more constrained pathways. It's hard to read here, but the upshot is that, in order to preserve that likely chance, or even really a medium chance, we're looking at global emissions having to peak sometime this decade and start being reduced pretty sharply thereafter, and even getting, you know, some of these pathways are requiring net negative emissions by 2050. So a short term increase in CO_2 emissions runs counter in some ways to the real need for short term CO_2 reductions, even if you're carbon neutral 100 years from now, or even 40 years from now, you've still got this period during which there's sort of -- you're putting counter pressure on what a lot of climate scientists think is necessary to mitigate the effects of climate change.

So carbon debt isn't just from Massachusetts, it's kind of a joke, but it's actually -- I want to spend some time with this because this is pretty serious -- and I hear this a lot, you bring up studies like the Manomet study that was done in Massachusetts, or the various studies done in the southeastern United States, all of them showing significant carbon debt, even when you're replacing fossil fuels with bioenergy. But in California the conversation tends to be different, we're just using waste and residues, right? So we don't really have that problem here. And it's very important to unpack these definitions of waste and residues because they get tossed about, I think even more so than sustainability in a very slippery and, I think, over-inclusive way when you're talking about how to do carbon accounting.

There are the residuals from a timber

harvest project that was going to happen anyway, there's a slash that gets piled up and burned or decomposes in the forest. I tend to think of that as -- that's the category that I'm talking about when I want to talk about waste and residuals. There is a carbon debt period associated with burning those materials, the time to decomposition depending on the size of the materials in the forest. There's been some work out of Finland, they just tried to quantify how long does it take different materials of different diameters to decompose. You may be looking at 10 or 15 years, I mean for the larger pieces, again, not that long really in the grand scheme of things, but a non-negligible carbon debt, even from those true residuals.

Where I think you get into more trouble is defining ahead of time trees on the landscape right now that are currently growing and living and sequestering carbon, the whole trees, in other words, defining those as residuals because a policy determination has been made that that's over-stock that needs to be cut, it needs to be thinned. That's where I see this slippage a little bit and it's very unclear to me when I read different presentations, different studies, how that -- what assumptions are being brought to bear there, because of a living growing tree is continuing to sequester carbon over time. I mean, even if you think it's over-stock and it needs to come out, even if you think it's a fire threat, over time if you don't cut that tree down and burn it, it will continue to grow, it will continue to store and sequester carbon. And that is going to lengthen that carbon debt period considerably to the point where you get to where I think Mitchell 2012 calls "carbon sequestration parody," it's not just the time to grow back, it's the time to replace the lost carbon sequestration of the tree that you cut down and burned because, when you cut it down and burn it, you turn it into CO_2 instantly and very efficiently. I mean, it's basically a 100 percent release. So for carbon accounting purposes, it does not make sense to sort of wave a wand and say that these are all -- these things that we want to cut are all by definition residuals, they're not, they are growing trees, whatever the management proscription is that you bring to it.

I want to get into a little bit, just a couple of studies to localize the studies that I've looked more at our part of the country, you know, California, Oregon, Southern Cascades down through the Sierras, really looking at whether this idea that I think Kim talked about, that when you go out and you thin the forest for fuels reduction and fire suppression, you're actually increasing the carbon stock in the forest. And the Campbell article is very interesting because it's a literature view, but it looked at how much carbon actually has to come out of the forest in order to prevent the emissions from wildfire. And again, it was comparing the carbon taken out of the forest to the emissions from a wildfire and found that, even in a Ponderosa forest, you've got to remove about three times as much carbon from the forest in order to really reduce fire severity than you would ever save in wildfire emissions. That's for a couple reasons, most emissions in a fire are from the vines or from branches and needles, they're not from the big trunks of the trees, which are often not consumed, even in a high-severity fire, and also because you don't know where the fire is going to happen, you have to treat more acres of the landscape than are going to burn, so there are areas of the landscape that may be treated where you don't have any avoided wildfire emissions. He also found, and there are other studies that back this up, that if the forests with the low frequency high-severity fire regimes tend to store more carbons, tend to have better carbon stocks than the flip side, the high frequency low severity fires.

Hudiburg, et al., again, a study out of Oregon State, looked at 19 ecosystems, 80 different forest types, three different treatment regimes, found that with the intensive thinning for bioenergy, there was a carbon debt that these facilities were carbon positive in terms of emitting to the atmosphere over a 20-year period across pretty much all of those forest types. It's where those forest types were already carbon sources that she found that maybe there was some kind of net benefit. And those are the ecosystems that we're talking about in California, and that runs the gamut from the North Coast to the Southern Cascades down through the Sierras. Again, these are local studies that are showing that there is a carbon debt issue, even when we're thinning for wild fire when we're using that material for bioenergy that displaces fossil generation.

This slide is probably understated. I know this is sort of the sacred cow in a lot of ways, but every once in while I think it's important to take a step back and look at our fundamental assumptions, and the assumptions that we bring to the conversation about forests and fire and the need for thinning. There is this idea that high-severity fire is unnatural and studies are actually showing that high-severity fire return intervals are much longer now than they were pre-settlement. There are historical records from the 19th, early 20th Century describing large patches of high-severity fire throughout the Sierras. The idea that the high-severity fire only occurs as a result of fuels spilled out from fire suppression is not really borne out by the evidence that exists.

There's this idea that fire suppression leads to overstocked forests, which leads to catastrophic fire. Again, I've probably understated it here, but the empirical data is showing that forests in California -- several studies in California, the forests that have missed the largest number of fire return intervals are burning predominantly at low to moderate severity, not experiencing higher fire severity than areas that have missed fewer fire return intervals. There's a study from late 2012 from the Klamath Forest Region that didn't even find any real trend in terms of the number of fires that occurred from 1987 to the present. So, again, this idea that forests are burning hotter, they're burning more frequently, etc., the empirical data doesn't necessarily bear that out, the studies that are out there have not borne that out.

Finally, this idea that we need to go at a landscape level and thin way deep in the woods in order to protect the things that we care about, talking about homes and communities, anyway, and I don't know, but maybe the same could be said for transmission lines, the treatments immediately adjacent to structures are really the most effective at protecting homes and communities, you don't need to go way deep in the forest to achieve that kind of community protection, the defensible space and some portion of the Wildland-urban interface, that really gets you there because fire does not have the same kind of momentum that a stone rolling down a hill would, I mean, even if it's burning in an area that got a lot of fuel, when it gets into a treated area, it drops off pretty quickly. And some of the slides that we saw earlier today showing that boundary, you know, with the fire burning in the untreated area, as soon as it hits that treated area, it drops out and you don't have to go very far into that treated area before you really lose the radiant heat that is causing the intense fire.

I skipped over the ecological benefits of high-severity fire. This actually is something that's very important in the Sierra Nevada, there are species that are adapted to high-severity fire like the black backed woodpecker, and there's also empirical data coming out showing that spotted owls like to forage recently in areas that are burned at high-severity. And there's incredible biodiversity, both plant and animal biodiversity, bird biodiversity especially, in these early successional snag forest areas. Now, there's an important caveat here. When you go out and salvage log it, you lose a lot of that diversity, you lose a lot of that ecological benefit. But, again, that's consistent with the idea that the high-severity fire actually is a natural occurrence. There are species that have adapted to it and will probably go extinct without it.

So sustainability, again, this is something I commonly hear in California, I've been working on especially private lands forest issues in California for quite a long time, and we often hear that California's Forest Practice Rules are so strong, we don't really need to worry about sustainability. So in the interest of being specific in what we're talking about, this is industrial forestry under the Forest Practice Rules, a recent shot of FPI land up in the Sierras. Forest Practice Rules are far from perfect. I mean, again, just talking about private lands, they don't do a very good job of human growth factor analysis. You can cut significant portions of an entire watershed in a very short period of time without CAL FIRE, really, I mean, in my experience without CAL FIRE really stepping in at some point and saying, "You've cut too much, you have to do something different," there's a focus -- a sustained yield often gets used, or sustainability often gets used to mean sustained yield, and vice versa. Again, just looking at a balance of growth and harvest doesn't necessarily mean that you're going to be able to maintain other ecological factors that are important.

And finally, the rules don't really address some of the practices that I think could occur with increased biomass harvest, and I think that's something that other folks have talked about and generally agree with, that if there is a sort of ramp up of extracting even true waste and residuals from the woods from steeper slopes, you know, taking more out than normally would be left there, and then we need to look at the long term effect on the soils, on other things, too. And I don't think the rules at present really account for that.

And again, thinking differently about fire, if high-severity fire has a role, is it sustainable to want to go out on the landscape and prevent high-severity fire from happening?

How does that fit into that and, again, what do you mean when you say "sustainable?"

I think one thing I'd mention here, Peter brought up the British subsidies driving pellet manufacturing in the Southeastern United States. There was an article in the Wall Street Journal this week, there was another article in the Economist back in April talking about this effect, and right now there's a tremendous demand for pellet productions, mostly being satisfied in the Southeastern U.S., and there are 100 plus year old hardwood forests and wetlands being cut down for pellets because of subsidies that are available in Britain and I think because of the bad carbon account and biogenic carbon accounting that occurs at the international level, there are some loopholes in the carbon accounting, that mean that those emissions will never count, really and, you know, among any party to the protocols that has a responsibility for reducing emissions, the United States not being among them. So that in my mind is an example of a policy subsidy that is driving a market -- it's creating a market, but it's creating it in a very unsustainable way. And, again, when we talk about unintended consequences, that's something to keep in mind as sort of a warning sign.

Air Quality and Public Health. Yes, burning biomass in a controlled facility reduces particulates, it reduces NO_x, and it reduces all of those things, as compared to open burning. But, again, I think that this is where some site-specific analysis really looking at the particular characteristics of the facility and its feedstock is necessary because you're replacing dispersed intermittent high emissions with concentrated constant lower emissions, and you've really got to think about who is immediately downwind of that plant 24/7, 365, for the next 20 years. Again, that's the kind of thing that can be dealt with, with air pollution control equipment, but you may have environmental justice considerations, especially if you're hauling stuff down to certain communities in the valley. Site-specific analysis is really important there.

Biomass fuel storage, I think whole tree chips are especially prone to spontaneous combustion, there are fungal infections and cost hazards for workers, and actually there's a lot of talk about methane and a lot of the greenhouse gas benefits touted for biomass depend on what I think are some pretty unrealistic assumptions about the amount of methane you get when wood decomposes in the forest; that's actually the basis of that Gregg Morris report, there are a lot of assumptions about methane in there that I don't think necessarily would hold up to scrutiny, but you do get methane out of biomass storage piles, I mean, if they sit there for long enough, you might get enough anaerobic activity to start generating some methane out of that. That's something that doesn't really get discussed. Again, water use -- I'd be interested in seeing some of the water work that's going on in Berkeley, but these plants actually can, depending on the technology, use a fair amount of water, and if you don't have an on-site water supply, or you don't have a place to put it, that might be another issue. Again, the site-specific analysis -- this is from Cabin Creek again -- the site-specific analysis is where you need to tease that out.

So to get to some policy recommendations, I mean, again, focusing on SB 1122, it's the law, it's going to be implemented, but I think that there are some ways in which, you know, I would propose trying to focus the location of those facilities in such a manner that is kind of conservative in terms of the environmental impacts, both the greenhouse gasses and the forest impacts, to really focus on trying to the extent that you're limiting open burning, limit open burning from projects that are already happening from the industrial timber projects, from the thinning projects that are already happening, not to go out and try to incentivize -- and they put these facilities in places where you're going to need to go out and cut a whole bunch of new green trees and then say, "Well, we would have burned those in the open anyway, so it's an offset." That actually doesn't really work. So look for the areas where you're actually going to reduce open burning, that would be one thing.

Also focus on the thinning that is most critical for protecting homes and communities, make this easy for folks that are doing defensible space, focus on the areas around the facilities, the homes and infrastructure that you want to protect. And also do that for site-specific impacts. There was some talk about a Program EIR, which is an interesting concept and I think one that I think is exploring to a certain extent. I mean, you kind of have to have a lead agency that had some discretion in where to site these facilities. And the way SB 1122 is set up, it's kind of like all these things, I mean, you just sort of leave it up to the County Board of Supervisors whether they approve it or not. So there may be some kind of structural issues there, but also, you know, when you're tiering off of that document, assuming one was done, there still would have to be these real site-specific impact analyses and also some really good cumulative impact analysis when you're talking about what's actually out there on the landscape. When you start multiplying the fuel sheds across the landscape, you do it in kind of a willy-nilly fashion, you could really end up with some conflicts, either over-use of the resource or the facility is not really being able to sustain themselves because they located too close together without doing a good assessment of those areas and, finally, looking at some ways to protect forests from effects of intensive biomass harvest.

The last thing, I think, is really just kind of what I'm trying to bring to the conversation. I think it's important, I mean, I know there's sort of a tanker ship, to use the cliché that has been launched that is California biomass policy, and it carries with it -- it's freighted with these assumptions, but I think every once in a while it's really important to go back and examine the science, see what's coming out recently, look at the empirical data, and really start to think about whether those assumptions still hold and whether those assumptions justify the further expansion and, to put it back into terms of costs and benefits, whether those benefits are enough of a justification to impose the costs, both accurately quantified environmental costs, and also the cost to Ratepayers and taxpayers, of starting a market that the market itself is not currently supporting.

I would just leave you with this last thought, this is just a reminder that we're talking about a pretty limited resource and we're not going to solve climate change by burning trees for electricity, there's just aren't that many trees. And forests have to do a lot of work, they have to do a lot of different things, they have to support a lot of different communities, water quality, wildlife, and asking them to bear the brunt of a growing electricity grid is a huge undertaking.

So I really appreciate your attention and thank you for not throwing anything at me, maybe you can do that during questions and, again, thank you so much to the Commission staff for asking me to tell you in 10 minutes or 20 why everything you knew about biomass was wrong. So, all right, thanks.

MR. MARISCAL: Thank you very much. And I will open it up now to the panel to ask or respond to any of the presentations that were given.

MR. TITTMAN: Just a quick response. I just wanted to clarify when I was making the point about the carbon debt, there is no atmospheric difference -- your point is well taken -- there is no atmospheric difference between biogenic versus fossil carbon. The point is that, when you use a carbon debt, you're actually using the biogenic carbon that in the future will be replaced versus what would have happened is that you would have been using fossil carbon and would it come from a geologically stable reserve and gone into the atmosphere. So there's not a functional difference in terms of its effect, in terms of irradiative forcing, but there is in terms of its origin and its lifecycle within sort of the biological path.

MR. BUNDY: And just to respond, I mean, I understand that. I mean, I think there is also a very -- I mean, although geological carbon storage is much much much longer term, I mean, it is effectively permanent, and storage in biogenic carbon is a lot shorter term, it still can be fairly long term storage. And in terms of sort of like the policy relevant timescales that we're looking at in dealing with climate change mitigation, even storage on the order of 100 or 200 years, even though it's biogenic -- and, yes, it will eventually return to the atmosphere -- we're making these kinds of policy decisions by climate change mitigation, and I still think that's a relevant time period. Again, keeping straight carbon stocks and carbon sinks, one being what's on the landscape, the other being the flux back and forth; to the atmosphere, those stocks really matter and I think that sometimes they tend to get overlooked a little bit. We're also in a situation where a lot of native forest is gone, there's a lot of biogenic CO_2 that is already up in the atmosphere, and it's not coming out any time soon unless it's getting dissolved in the ocean, because we're not managing land in a way that it's actually going to replace that primary forest.

MR. MARISCAL: Go ahead, Kim.

MS. CARR: I have a question for Kevin. You know, I've been working in the rural forested communities for over 15 years and doing nothing is really not an option. And so we've got to figure out how to balance the multiple interests of the stakeholders and not wrap ourselves around one or two issues -- like the carbon issue is a big deal and we need to address it, but we need to balance it. And what I'm seeing is just a more deprived community with less capacity to actually manage the resources with higher risk of igniting the fires; so needing to keep the people in the equation here and then, also, certainly talk about the science and the multiple benefits. So I'm just curious as to, you know, what is the option, is it do nothing and leave the forest where it is? Or is it more of an approach of figuring out where appropriately we can use bioenergy and fit it into some of the solution?

MR. BUNDY: I mean, that is the question, I think. And I think that -- and it's a very hard question, I mean, when you're trying to strike that kind of balance because it requires a sort of near clairvoyant wisdom that human beings don't always tend to demonstrate in either the environmental or the social context. I mean, as I said at the end of the presentation, you know, I think with respect to these small scale facilities really focusing on defensible space, focusing on improving air quality where you can show that you're doing that, not getting too far out into the woods with a bunch of new thinning projects. I mean, I don't know how the communities you're working with balance the protection of their homes and their communities against the economics, against the job creation, with the forest restoration component, whatever "restoration" means, it's like "sustainability," you know, it's a fairly loose term. I mean, I think that's something that is just going to have to be worked out. I mean, I think a lot of it is going to be kind of community specific, different communities are going to have different ways of valuing those things.

I would prefer to at this point be very conservative from a carbon standpoint and from the standpoint of really going out on a large-scale landscape level thinning driven by the creation of a bioenergy infrastructure. I mean, whether you do that with 50 little plants or a bunch of big plants, you know, I mean, you could still have some real effects on the forest not just from the logging, but also from the long term ecological implications of trying to eliminate high-severity fire. Maybe just recognizing that there's an important role for high-severity fire ecologically is just adding that into the equation. I mean, again, these are conversations going on all the time with the Forest Service, probably know the stuff better than I do, but I don't hear that conversation happening here and that's part of why I want to bring it in.

MR. MARISCAL: Any other comments or questions from the panel?

MR. TITTMAN: One other clarifying point with regard to the renewable obligation credits that the UK government issues. They actually are required to comply with EU standards for carbon accounting for those feedstocks. So, I mean, anybody can call into question any protocol under -- not saying you can't call that into question, but there is an established and rigorous standard where they actually measure the carbon intensity much like with the Low Carbon Fuel Standard and the RFS here, that allows those entities that are burning the pellets produced, whether it be here or from Canada, from the beetle kill, or from elsewhere in the world, they actually do have to comply with a fairly rigorous criteria for greenhouse gas emissions in the supply chain.

MR. BUNDY: I'd like to follow-up with you and just sort of understand what the assumptions are that they bring to that --

MR. TITTMAN: Sure, yeah.

MR. BUNDY: I mean, a lot of times you'll dig into those things and discover an assumption that biomass is carbon neutral, and I don't know if that's what they're bringing to it, if they're doing a more sophisticated lifecycle analysis than that, I just don't know, so I would be interested.

MR. TITTMAN: Yeah.

MR. MARISCAL: Thank you. Any other comments or questions from the panel? Okay, with that, I'd like to open it up to the floor if there are any comments or questions. Michael.

MR. THEROUX: Well, Kevin, I wish you'd given your presentation at the starting so your minority position should have been appropriately positioned for everyone to respond to today. All in all -- Michael Theroux, JDMT -- all in all, a good wrap-up session for all three of you. And Kevin, I do appreciate your intensity on this.

Kim has obviously been involved on the ground, as you said, for 15 years in the stewardship development programs having to do with managing the forests' understory, and the homes and the lives and the economies within that. That's the same issue that our National Forest Service has been struggling with for about 15 years, easily. And something has changed. As you well, know, we now have a new Forest Rule, and we now have a new template for what you're referring to exactly, which is large scale, landscape scale management of the biomass. And the thing about it, I mentioned to Kim before this, is that every single one of those 22 funded programs so far is different; every single one of them comes at the question of what are the elements of the community, who are the players, the stakeholders, or the economic interests, how much biomass is there, what are the environmental conditions that are there, and none of them are the same. The thing that is the same is the Forest Service on a national basis has agreed to work with the communities that surround the national forests and listen to them and let them cut their own cloth, and implement it on the ground on a daily basis. And involved in this are all of our Forest Stewardship Council and SFI Certification Programs and, in many cases, there's folks on the ground with a clipboard just like your organization saying where and where not to, and that's important.

So the national trend is trying to struggle with this, as well. And you've done a very good job of running your hand across all of the splinters and pointing out those areas of contention, and those are the ones that we struggle with every single time. The concept that I brought up earlier over programmatic, Kim was able to refine a little bit in that these are very regional questions, and tiered within that, then, become the very specific conditions of the economics and the stakeholders themselves, and the environmental conditions, and it's very important that your crew be on the ground to talk about the biodiversity, in particular, and bring the other side of the coin up, and I see that you're working on that, and coming to some nice conclusions.

Peter, you indicated and I agree with you that clear metrics for sustainability must be arrived at. For the past three years, I've been a member of the Air Board's Low Carbon Fuel Standard Sustainability Working Group and, believe me, that's exactly what we've been attempting to do; we're comparing internationally all of the various pieces around the table in sustaining the biofuels, and all of the tangle on palm oil, and all the various aspects, trying to look for what are the metrics for sustainability and what does that term mean in terms of accounting on the ground. Here is the status quo, you want to bump it a little better. You want to improve the sustainability, make it more sustainable, so what is sustainability? Oh, I don't know. Can we make it more sustainable? Now we can start to agree on something. The underlying criteria of how we tick off environmental justice, environmental quality, economics, all enter into that equation. And recently, very recently, Mike Waugh who was presenting earlier -- we've done our job too well in the Sustainability Working Group, it seems, because what we're talking about is applicable across the board, not just to biofuels. So these precepts of how we judge and establish metrics for sustainability are now being looked at in terms of, well, we need to apply that to Cap-and-Trade, we need to take a look at that in all of these other areas and contexts. We're getting closer, we're not there yet, it's a monumental undertaking. But we also recognize that California is its own country with its own global economy, and if we can establish a reasonable assessment of the metrics of sustainability and how we would implement that on the ground for biofuels, that it will lend itself to all of these other areas. You know, we've been somewhat myopic on biofuels itself, but it flows over into a lot of other areas.

Kevin, I would be careful, please, when you use the term "combustion." Classically, we know that combustion is any time you pop carbon off the end of the molecular chain -- yes, that's combustion. And it's been loosely and poorly defined in the context of what we're talking about. And I think it helps to look at -- where the Stoichiometry is, nobody wants to mess with that kind of high detail stuff. But, yeah, scientifically it is combustion, but gasification and pyrolysis and the other factors of thermal conversion that continue and that we're talking about certainly are to open burning. And if we're going to get that pointed, then utilization -- you and I, especially -- at this level that we're at, we need to be careful about the use of those terms and differentiate and say so as we're using them so we don't mix that pot any worse than it already is.

Other than that, thank you, this panel, very much for hitting this so hard and working on it like this, this has been -- for most of us, as Doug Wickizer would say, it's the same old bone we've been chewing for an awful long time. Thank you.

MR. MARISCAL: Thank you. Are there any comments or responses from the panel?

MR. BUNDY: Yeah, just on that point about combustion, I certainly appreciate that, that none of what we're talking about is the same as open burning, I mean, you know, a stoker boiler is not the same as open burning, especially if you've got at least some kind of PM control on the flue. But you don't get energy out of wood without combustion of some sort, and even at a gasification facility, running it through an IC engine is -- so when I talk about combustion, I'm just talking about the eventual burning of the hydrocarbons that the heat from which makes energy. And I think it is actually appropriate to call that combustion, especially when you're talking about CO_2. When you're talking about some of the other stuff, I think you have to talk about the emissions rates that differ from different kinds of combustion, but that's why I'm -- I'm actually very intentionally saying "combustion" in these contexts. We could disagree over the terminology, but that's the reason. But thanks for the point.

MR. MARISCAL: Go ahead, Kim.

MS. CARR: Yeah, thanks for your comments and I agree that we've been chewing on this same old bone for quite some time. And, Kevin, some of your comments were so reminiscent of the timber wars, and I think that, I don't know, being a facilitator and talking to people on all sides of this, no one wants to recreate that, the over harvesting that's occurred. And certainly models like taking hard wood across the Atlantic to feed energy in Europe, those kinds of things, I mean, I don't think that's what we're talking about. And the fact that SB 1122 has maximized the facilities to three megawatts or less has us targeting them in high fire -- in fire risk areas, has the legislation riddled with words like "sustainability," and also the Bioenergy Action Plan, "sustainability," "community-sized," etc., tells me that this is not about setting up policy where we're going to fail again, this is about going in with our eyes open and really balancing the approach so that we don't have the unintended consequences. But I do think that we have to make space for multiple issues and, you know, CO_2 being a big one, but then looking at all the other opportunities and challenges within this.

MR. MARISCAL: Thank you. Anything else from the panel? Any other questions? Pat.

MR. HOLLEY: Yeah, late in the day, I'll try to keep it short. Just a couple of questions. I wonder, why does California Department of Forestry and U.S. Forest Service spend hundreds of millions of dollars per year suppressing fire and putting the lives of thousands of firefighters at risk every day during the summer fire season? Some of the comments that were made would lead you to believe that fire is good, and I know you don't mean that in a personal way to the population of our state, but I think that's the message that comes across. There are good reasons why the California Energy Commission determined that biomass energy complex to be carbon neutral, is based on that temporal argument that is well documented in the CEC report that classifies these facilities as carbon neutral.

A couple other just local observations from my experience here in California. Last year we had an enormous fire season. It personally affected me and many of the people I work with in the Lassen. The Forester made a decision to allow a fire to run, it started as a small fire, could have put a lot of resources on it early, but a decision was made to let it run. It ran to over 60,000 acres and destroyed the resources that we all depend on. It left 45,000 acres standing, but dead. It can't be harvested, certainly not in time to get any salvageable timber value.

That leads me to the next step in the scenario, which is the severe high hazard fires that will occur at some point down the line. The story fire was involved in this, which was a previously burned area with large stands of standing dead trees; it burned through the story area, I think that was about 4,000 acres, and it scarified the soil, it burned with such intensity there is no life there except a very few snags that are remaining.

So I think there are a lot of good reasons why California has taken a lot of control measures and has fostered a biomass industry. One very big factor is that, because in Northern California this industry only removes 25 percent of the annual growth of the forest. So it's a sequestration, it's a sink that is functioning very well. And we want to keep it in balance. We believe that managing our resources wisely is very important.

One more item about that Lassen fire. It also caused PG&E to have to spend a great deal of money and it affected one of our facilities, as well; it crossed the Caribou Transmission Line and destroyed -- and stopped PG&E's ability to transfer electric power for 21 days into Northeastern California. Our plant in Lassen County was one of the only facilities around that could generate enough power to keep Lassen County going, but we did so and PG&E suffered great losses and put its personnel at risk out restoring service for 21 days during the fire season. So I think there are a lot of good reasons that we need good forest management practices. I just wanted to give you a little bit of local color there. Thank you.

MR. MARISCAL: Thank you, Pat. Any comments or questions from the panel?

MS. CARR: Well, I just want to add one thing. Typically how the public forest budgets run is that first the dollars go to fire suppression, and then what's left goes to more of the preventative measures and the more ecological restoration measures, so it's been a real challenge as we go through these seasons where a lot of the budget is eaten up by suppression, and then there's not much left to do the preventative measures, or restore due to some of the post-fire impacts that you were identifying. And then the Chief with the Forest Service announced about a month ago that they're actually going to be doing less fire suppression, and I think it's all related to the budget sequestration and that. So this will be an interesting year as we're on high alert already and we're moving into the fire season or, in some cases, New Mexico is well into it, and just to see how they determine what they'll put resources into for suppression and what they won't. We're in a new era related to this.

MR. MARISCAL: Any comments from Peter or Kevin?

MR. BUNDY: Yeah, I feel like I don't -- I don't want to be misunderstood and I don't want to be mischaracterized as saying that I think any of the things that you're talking about were good things, you know. I'm not saying, you know, "Yeah, we should let the transmission lines go." I mean, that's not a fair description of what I'm saying. I think what is really important is to really look at the data, to look at the empirical studies that are coming out, to look at the role that high severity fire can play in the landscape, the ecological importance, the niche of that event as a natural event, and to factor that into some of these conversations. That doesn't mean that every fire should burn at high severity, not all fires do burn at high severity. I think there's a lot of emotion wrapped up in this, I mean, I certainly have lived in rural California, I've been afraid of fire, and there are fires that are very very destructive to human communities, and I think that the focusing on trying to do what's necessary to protect those communities and that infrastructure and keep those costs down is actually really important. Does that mean we need to go out at landscape level and make sure that we never have a ground fire again in California? I don't think so. I mean, you mentioned the Forest Service process; with respect, there's some things we disagree with the Forest Service on, you know, we have for many many years. So just to clarify where I'm coming from with that, I think is important. This is a really tough issue and it's tough for me to sit up here and take this position, but I think there's support in the scientific literature for some of what we've been arguing and I'd like to see that considered in this conversation.

MR. MARISCAL: Thank you. I think we have a comment or a question from the phone line, Kevin Best from Real Energy. Kevin, just one second, we're going to unmute your phone line. Still working on it, Kevin. Well, Kevin, I guess we can't unmute your phone line, so we will read your question.

MR. TANG: Okay, so Kevin Best from Real --

MR. MARISCAL: The stars are just not

aligning for Kevin.

MR. TANG: So Kevin Best, Real Energy, wants to comment that "Tim Olsen and others earlier today had identified the single most important action to get projects built that are probable today with the LCFS credits. Given an agency like the California infrastructure and economic development bank the opportunity to broker credits given the development community long term contracts for discounted credits and let iBank keep any spread."

Chuck White from Waste Management also suggested that, in the biomethane proceeding that we had on Friday, "…and we think that this is the single best idea to get real projects built now. Real Energy would be pleased to participate in this effort."

MR. MARISCAL: Thank you, Kevin, for that comment. Is there any response from the panel at all? Are there any other questions or comments from the room? Okay. With that, I think we will adjourn. I really appreciate everybody's participation and I appreciate the panel. Thank you very much. Just a reminder, comments are due June 17th by 5:00 p.m., please submit them to our docket email, docket@energy.ca.gov. Please also cc me at gary.oneill@energy.ca.gov. Please include our Docket Number of 13-IEP-1M and the title "Status of Bioenergy" in the subject line. I appreciate it, thank you. Have a great evening.

(Thereupon, the Workshop was adjourned at 4:38 p.m.)

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