JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	) Docket No.
Preparation of the 2009 Integrated Energy Policy Report (2009 IEPR)	) 09-IEP-1P
	)
Staff Workshop on Commercial-Scale Geologic Carbon Sequestration and Policies to Support California's AB 32 Goals of 2020	)
	)

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

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Martha Krebs

ALSO PRESENT

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Hydrogen Energy

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ALSO PRESENT

George Peridas
Natural Resources Defense Council (NRDC)

PUBLIC COMMENTS/QUESTIONS

Susan Patterson
Gas Technology Institute

Richard Myhre
Bevilacqua Kight, Inc. (BKI)

Will Johnson
Visage Energy

Pierre du Vair
CEC

I n d e x

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P R O C E E D I N G S

9:02 a.m.

LARRY MYER: My name is Larry Myer from the PIER Program at the Energy Commission. And good morning to those as well who are connected via WebEx. So this is a electronic meeting as well as in person.

And so to begin with I think we should start with just a safety note and housekeeping comments. For those of you who are not familiar with the building, the closest restrooms are out this exit and to the left. And there's a snack bar up on the second floor under the white awning. And lastly, in the event of an emergency and the building needs to be evacuated, please follow one of us with these necktie things here and we'll lead you across the street to the park which is Roosevelt Park which is diagonal and that's the place where we assemble in case of an emergency.

So, just another couple comments on the format. Since this is WebEx, we will have the opportunity for questions, both via the phone line through WebEx and also for those who are listening, they can send in written comment -- written questions through the electronically and we'll pick those up as well. So we'll do both questions here from the folks in the room and from the Web.

So next I'd like to thank all of the presenters, panelists who have come. Some have come from quite a long distance to participate in this workshop. And we're delighted that everyone could come and talk about this very important topic. And with that, I think I'd like to introduce Dr. Martha Krebs who's the director of the Public Interest Energy Research Program and she can make some introductory remarks as well as provide an update on the CCS technology/development aspects. So with that, Martha.

MARTHA KREBS: Thank you, Larry. It's good to be here today and I want to join Larry in thanking the panelists for their contributions to this type of workshop.

First of all, I think it's important to put what we're talking about in some perspective with respect to the Bi-annual Integrated Energy Policy report, development that is -- goes on here at the Energy Commission every two years. The -- within this process, we look at pretty much every aspect of the energy business here in California and the report itself becomes a foundational document for the development of policies that deal with resources associated with energy, both directly and indirectly. It addresses issues associated with protecting the environment, insuring reliability of our energy system and protecting the State's economy as well as public health and safety.

And in this session of the, you know, of the 2009

IEPR, as we call it, there will be more than 30 workshops in the next few months. So this is a, almost, a forced marched, but results in a product that has been very valuable to California over -- since it's inception.

The -- in order to think about Carbon capture and sequestration, we have to think about it really comes into play within the framework of climate change and solutions that has been established by Governor Scwharzenegger and the Legislature in 8032 to deal with approaching the climate change, responding to climate change, both from a perspective of litigation and adaptation.

The mitigation approach that we have taken in California is relying on a portfolio of technologies and within the framework of that portfolio, we've placed carbon sequestration especially associated with large-scale sources of CO2. And within California, there are large industrial facilities that have significant CO2 process or exhaust streams that could be secured in a long-term storage.

The focus in, currently, alternative fuels also may give us an opportunity for carbon sequestration and also from the perspective of both nationally and in California, it enables an orderly transition from fossil fuels to alternative sources of both automotive fuel and electricity.

This is just to remind you that California has aggressive goals for greenhouse gas reduction. And in large measure, here in the -- the work of ND 32 is focused on the 2020 market. And -- but the long-term issue of the 2050 targets are where the carbon sequestration -- the option of carbon capture and sequestration come into play. What we do, both in California and in the nation over the next decade will demonstrate whether or not in the period beyond 2020, carbon capture and sequestration is a capable, reliable mitigation measure for reducing CO2 emissions.

And so, in large measure, that is what as how we have pursued or thought of carbon capture and sequestration within the Public Interest and Energy Research Program.

So we have actually, this is the third set of hearings or workshops that the CEC has had upon carbon capture and sequestration. We had a first in 2005, a second in 2007 and the question is what has changed in the time that -- since the last IEPR review. And there are a number of things. Obviously, 83rd-2 (phonetic) is going on, but we also have the possibility of a commercial power project with CCS being brought to the Energy Commission for permits, for siting permits.

The Low Carbon Fuel Standard has been adopted and you're going to be hearing about the implications of that for carbon's capture and sequestration in some of the panel discussions later today.

We have very active climate/energy legislation going on right now and Congressman Waxman expects to have the mark-up in the House by the end of the week.

The -- we have a lot of action and interest in development going on at the state and regional level, in the development of cap-and-trades as a backup, if you will, to the Federal effort. The regional partnerships, which I'll talk about a bit more, especially in the context of the West Coast regional carbon sequestration partnerships, are all proceeding to a Phase 3 stage and at least describe a bit of what's happening in WESTCARB with that regard.

Of course, the Stimulus Bill on Friday, Secretary Chu announced that $1.5 billion would be available for the carbon capture and sequestration demonstrations from industrial sources. And that industrial sources encompasses not only refineries, but also possible power plants as well. And non-coal power plants which is a significant broadening of what's been considered in the past.

The -- all the States are tackling carbon capture issues and there's been a lot of development at the international level. So it's time to review this. We've upped again.

The DOE Regional Partnerships Program, this is something that was begun in 2003. There are seven regional partnerships throughout the United States. They have expanded in the time since their creation to include Canadian provinces and they have looked at both directional and carbon sequestration, but their concept from the beginning was to be broader than that. Not only were they to address technical issues and resource assessment from the prospective of both, what are the sources of CO2 in these regions, but also what are the capacities for long-term storage.

But as important as anything in the conception of these partnerships was that they were to be located in and involved with public entities, such as in the case of the West Coast Partnership, the California Energy Commission. And that was because it was recognized from the beginning that institutional issues were as important in developing this technology and this option as technical issues.

WESTCARB, the West Coast Regional Carbon Sequestration Partnership, has grown to more than 80 organizations and the California Energy Commission Recruiter, their program is the manager of that, of this partnership. It has helped to inform policy and AB 1925 was passed, I think, in 2007 and required a report which was prepared in 2008 and then a follow-up report will be heard in 2010. Actually, I think it was 2007. We included it as part of the IEPR process.

The WESTCARB has also participated in the discussions of the 8032 Economic and Technology Advancement Advisor Committee and as well as the Environmental Justice Committee. I think it is important there are, I guess, by now nine other states in -- or eight states in the, eight other states in the Partnership and we serve them as well.

Going through this as quickly as I can, this -- the first part or an important first deliverable of the WESTCARB project was to map California's industrial carbon dioxide sources. And power plants were the largest point source type, but there were also significant oil refineries in coastal urban areas, cement and ethanol plants in the Central Valley and inland to Empire. And bio-fuels plants as they develop could be an important source for CO2, carbon capturing sequestration.

The other early deliverable was a broad characterization of geologic storage opportunities in California and as you can see from this line, the Central Valley is a significant opportunity and also the natural gas and oil fields that are scattered throughout the State are also possibilities, not only for sequestration in depleted fields, but also for enhanced oil and gas recovery if that's appropriate.

The WESTCARB is currently, as part of the second phase, is conducting a pilot scale field test with the Arizona utilities at one of their coal plants. And this is quite small, only 2,000 tons of CO2. And it will be followed later this year with a similar size pilot field test in California with Shell Oil. And these, then, will provide information and experience for the Phase 3 larger scale project at -- for which sites are currently being characterized. And the -- this Phase 3 is significantly larger whereas the earlier projects are 2 to 5,000 tons and a few weeks of injection. This will be 250,000 to 500,000 tons over three years with a significant follow-up period to assure that we understand how the gas behaves after injection.

WESTCARB, as I indicated earlier, an important part of WESTCARB has been stakeholder engagement for both the terrestrial and a geological sequestration activities in Phase 1 and Phase 2. We've had meetings in not only California, but in Arizona, Oregon and Washington State and as well as in Alaska. We have had many briefings in other participational meetings and public meetings.

So in -- I want -- the next two slides are kind of summaries of the challenges for CCS. And although there are real technical challenges for carbon capture and sequestration, in many ways it represents the new application for the existing technologies but with a different scale in terms of physical scale and the sense of time frame in which implementation may have to occur.

There's cost issues associated with the surface systems mostly with respect to carbon capture, installations at power plants, refineries, cement plant or alternatively a precombustion capture and then industrial, a variety of industrial sources.

There's a general consensus on the methodologies and approaches to the -- to assure health safety and environmental protection, understanding the impacts of leakage of carbon dioxide, brine migration and pressure during the lifetime of both injection and post-sequestration and then also seismicity.

The storage capacity, we -- although we understand well that the, for example, the Central Valley is a major sort, has major storage capacity, each of the individual sites will be different and have different characteristics that have to be taken into account.

The other significant element is infrastructure and how you link carbon dioxide sources in a grid, pipelines that we're trucking, whatever, you know, building that kind of infrastructure. Again, it's well-known, but it is -- it needs to be thought through and evaluated with respect to both costs and environment health and safety. But these are things we have done before.

Perhaps more significant are policy challenges for carbon capture and sequestration. And in some respect, these become -- and I think within the framework of the Workshop put together today, this is really the focus for this Workshop because combined with the progress we're making and getting through the near term issues for plant negation and adaptation, the advancement of the partnerships, that makes three, and now the stimulus package opening up an opportunity for a very large sequestration project.

At the resolution, the approach at the federal and the state level to think of these policy challenges becomes more significant and more -- and not urgent. It's appropriate for us to think about these things, now more than perhaps before.

And so there are legal issues that we'll hear about today that are related to long-term CO2 storage or space ownership, the issues of subsurface trespass and liability. And then regulations for geologic sequestration wells, EPA has proposed new, a new underground injection well clasp to regulate carbon sequestration and the issues of how that will play out, what is the interaction between the states and the regions, regional offices, how is that to be managed.

The Low Carbon Fuel Standard basically, you know, bio-fuels in general offer an opportunity. They will have CO2 streams. If we were to sequester that carbon, it becomes an opportunity for a negative carbon, not just carbon locality. And then there is the financial uncertainty for these large field projects and the numbers of large field projects that we will have to be focused on over the coming years.

So I think that's my introduction.

MR. MYER: We have time for questions. Yes?

PRESIDING MEMBER BYRON: Larry, if I may. Dr. Krebs, is this the beginning of the end for you? We're losing you soon, aren't we?

MS. KREBS: Yes, sir.

PRESIDING MEMBER BYRON: And I'm very sorry to hear that. I don't know how we're going to survive around here without you.

MS. KREBS: Well, I have enjoyed my time here.

PRESIDING MEMBER BYRON: You had mentioned something off presentation about Secretary Chu announcing last Friday that a one and a half billion dollar available for covering capture/sequestration for industrial sources. I did not hear that. Do you -- do we know anything more about how those funds will be distributed?

MS. KREBS: It's only in a press release. And so we hadn't seen -- it basically announced that there would be a notice of intent. So I think we will see within the next day or two the notice of intent.

I think it's expected to be a competitive process. And, you know, so we'll find out exactly what is -- how they intend to go forward on that.

PRESIDING MEMBER BYRON: Thank you. Good. I look forward to learning more about that. Thank you.

MR. MYER: Anyone else? Okay. Please come to the podium. And as well, please state your name and your agency.

MS. PATTERSON: I am Susan Patterson, Gas Technology Institute. And I am sad to see you go, too. Sorry to hear that.

Question, are you planning on directing any additional PIER funds toward technology development for carbon sequestration technologies?

MS. KREBS: Our participation, all the phases of WESTCARB have required us to put in a 20 percent cost share. And that cost share has come from PIER. It includes funding from PIER. So, yes, over the lifetime of Phase 3, we'll probably put in five to six million dollars. That's a ten-year project and we'll probably put about five to six million dollars in.

MS. PATTERSON: But you don't plan to put any money out to bid for new technology developments? I mean, out for any competitive solicitation?

MS. KREBS: We haven't thought about that.

MS. PATTERSON: Okay, thanks.

MR. MYER: Thank you very much, Martha. Our second presentation is given by Elizabeth Burton from Lawrence Livermore National Lab. And before we go there, just a quick overview of what we're trying to do today with the, at least up until noon, overview of the agenda here.

We have two overview talks this morning. One on 19 -- the report to the Legislature for AB 1925. And that sort of sets a good context because of the -- we have to repeat, give an update to that report in 2010. So there's an important linkage between that report and what we're doing here today.

And then the second overview is on CCS Legal Regulatory and Institutional issues by Craig Hart who will then move from this podium over there to the desks and conduct a panel discussion basically on that same topic. And we have panelists representative of various stakeholder views on that, on those issues.

And then that will take us up to noon. Lunch is on your own. In the afternoon, we're going to then have a few more presentations, first on sort of an update on the advances on catracide (phonetic). Then, even though we'll be talking about it in the panel discussion, a little bit more in depth overview on California’s fuel standards and its implications for CCS and then talk on AB 32, an update on AB 32.

So with that, I'd like to bring Elizabeth up. As I said, Elizabeth was the first author on the first report to the Legislature for AB 1925.

MS. BURTON: Thank you all for coming this morning and good morning. I want to first give you a little bit of an overview of what AB 1925 is all about for those of you that aren't familiar with the Legislation, give you an overview of what carbon sequestration is all about on a very high level, and then kind of leap into the details of what was included in the AB 1925 report and what we think the issues and strategies might be for California to move forward with the technology.

There are some copies of the report available out on the table, you can pick them up. You can also download it from the Energy Commission website, so it is publicly available. And if you have comments on it, I would certainly appreciate hearing from you. We are scheduled to do a second report that is due out in November of 2010 and I'll tell you what the reasons behind that are in just a few minutes.

First of all, the components of carbon capture and storage are really pretty simple. There are three parts to it. You have to capture the CO2 from some kind of a point source that has large emissions. That can either be a power plant or some kind of industrial facility.

The separated CO2 then has to be transported. Given the large volumes we're talking about, that pretty much means a pipeline infrastructure for California. CO2 is then injected as a super critical fluid and this is kind of an important point because that means you basically have to be pretty deep to keep the CO2 at the right pressure and temperature for it to be a liquid and be dense enough for you to be able to put a whole pile of it into the rock formation. And we're targeting deep geological formations, three different types; saline formations, depleted oil and gas fields and even unlinable coal seams although that doesn't apply certainly as much to California as it does to the eastern or Rocky Mountain states.

The intent of AB 1925, I think it's important to make this point, when the Legislation was written, no one really asked, and Blakeslee and his staff didn't ask, whether CCS should be a part of California's Climate Mitigation

Strategy. They assumed that it was going to be, and the question that the Bill asked was what recommendations would the Energy Commission with the Department of Conservation make to accelerate the adoption of cost effective geologic sequestration strategies for long-term management of industrial carbon dioxide.

So from that, the Commission staff, Conservation staff, Blakeslee staff and others have basically reduced this to two fundamental questions: how much geological potential does California have and what are the types and locations of the major point sources; and then how well is California positioned technically with respect to statutes and regulations and economic considerations to move forward with this.

And given those two questions, they're really, sort of two conclusions for the first one or two considerations. California imports a great deal of its electricity and most of that is from coal fired plants out of state. It's 20 to 30 percent of our electricity and about half of the inventory greenhouse gas emissions from the power sector. Any CCS strategy really has to take this into consideration to be effective or optimized.

Within State, the largest point sources are natural gas power plants and then plants and refineries. And there are certainly different ways of dealing with those than you might use if you're just looking at power sector emissions.

And then what I'm going to spend a lot of time on is the first secondary bullet, the technical readiness. Other presenters will cover the regulatory and statutory issues and the economics. I'll talk a little bit about risks and risks management. We have a lot of analogous industries to draw from on understanding the risks and managing those effectively. And then I'll be looking at some of the favorable opportunities that were identified in the first report and we have a few suggestions as well for further work, some of which we will be pursuing in the second report which is due out 2010, as I said.

We basically decided to write that second report in consultation with the Legislative staff because so much is happening in CCS and will be happening. The conclusions of the pilot studies, a lot of the early commercial work will be coming out in the next couple years. So we thought having the final say to the Legislature at the end of '07 really wasn't doing the best job for them. So we offered, silly us, to write a second report due in 2010. And of course you know the old line in the Legislation is always we'll use existing assets, no new funding. So anyway, we've committed ourself to a second report and that is why it's really important if you have comments on the first report to make sure Larry or I are aware of those.

A screening of sedimentary basins was done by the California Geological Survey as part of a WESTCARB study. They screened 104 basins using geologic criteria such as what the crossing and permeability was of the formations, whether they had suitable seals to trap the CO2, what the sediment thicknesses were and avoiding things like power plants or tribal lands or military installations.

Putting those screening on that 104, they eliminated 77 of the basins. Twenty-seven of them met those screening criteria and that still left us with 38,000 square miles of turf that are potentially good sequestration sites. This includes the largest ten basins in the State and includes the Sacramento, San Joaquin, Ventura, L.A., Eel River basins. So these are substantial sequestration resources.

The estimates using the National Energy Technologies Laboratory methodology for estimating capacity of just these ten is somewhere between 75 and 300 gigatons of CO2, depending what assumptions you make about porosity and injectivity and so on. There is a fairly large uncertainty in making those estimates. But still, it's certainly more than enough to handle industrial source and power sector emissions in California for a very long time.

It's important to note within these basins that oil and gas fields are very common. These in and of themselves are potentially good sequestration sites. They have extensive capacity, about 5,000 million metric tons of CO_2. And the other important factor, I think, is this oil and gas has been trapped in structures, that have trapped -- these are buoyant fluids, so they tend to want to migrate upward just like CO_2 does. But these basins have the capacity to trap these things over geologic time scales for millions of years, in other words. So, they've been demonstrated through geologic time to be good traps.

If we look at in-state point sources compared to locations of basins, this is, I think, an identical map to the one Martha just put up, we find the largest sources are natural gas shown by the kind of maroon color there. Coal power, you see one little plant in yellow down at the far end there. Cement and refineries are the other big sources in the state. And these are pretty well located with respect to the ten largest basins or the sink sites. Ninety percent, in fact, are within 50 kilometers of a potential sequestration site.

However, having said that, and keeping in mind how much electricity we import as well as transportation fuel that we export, I think it's important for California to approach CCS in a regional context.

Electricity imports, again, into California. Twenty-two to 32 percent is kind of the range over the last couple of years of the greenhouse gas emissions inventory, 39 to 57 percent of greenhouse gas emissions. Transportation fuel come out of California and go into neighboring states. We expert the fuel, we don't export the carbon. We import the electricity, we don't really import the carbon although we are counting that as part of our inventory.

So does carbon really flow with the energy and should it? These are considerations that not only the inventory has to make, but also in credits or cap-and-trade system or the potential for actuals. Some people have talked about taking Wyoming or some state where we buy a lot of electricity and piping this stuff into -- piping the CO2 into California, but I won't go there.

How does each state then meet its individual carbon emissions goals in that context apart from what it's doing within its own borders. So I think it's important to keep that in mind.

SB 1368, which put in a mission standard on long-term base of power purchases, is another consideration because this certainly affects imported coal generated power. Again, imported power is 60 out of the 107 million metric tons in the 2004 Greenhouse Gas Inventory. Addition of CCS would allow these coal generating power stations that send their electricity to us to meet that standard which is defined as 1100 pounds of CO_2 per megawatt hour.

But in the 2007 IEPR, the conclusion was really that commercial scale demonstration needs to happen because at that time, the investors were already sort of walking away from new coal plants. And so CCS was probably not likely to be available to meet at least the short-term 2020 goals and maybe might even be a long shot unless investor confidence and the financial markets change for 2050.

However, that opinion, given federal programs and other ideas that people have had in state, like hydrogen energy for coal fuel commercial projects, really, I think, makes that opinion something that needs to be re-examined.

Other early economic opportunities that were identified in the report include ethanol and bio-refineries as Martha mentioned previously. We don't have very many plants right now, so they're not going to make a big dent in our current emissions inventory, but if we went that direction for transportation fuels there, we can certainly expect a lot more of them to be built. Twenty-five hundred metric tons of CO_2 are produced for every million gallons of ethanol and these emissions are pretty much pure, so you don't have to go through the economic pain of putting a separation and capture plan onto your facility. And separation as you will -- you either know or will hear about is by far the largest cost associated with CCS.

And these provide negative emissions, so you kind of can double count them against the inventory because they're using plant matter that takes CO2 out of the modern atmosphere, not fossil fuels.

Another option is Syngas/Pet coke of hydrogen as the Hydrogen Energy Project is pursuing, we're soon to capture integrated into pre-combustion process.

Other opportunities are for enhanced oil recovery using captured CO2. And the reason this is attractive is that it creates a value for CO2 and that improves the project economics and these may be very viable early opportunities within the State. We have a lot of oil, up to five billion barrels of additional oil that could potentially be recovered if CO2 EOR was available.

Right now, CO2 enhance recovery is done a lot in other states. They have a lot of experience. They have natural CO2 reservoirs that make the CO2 very inexpensive. Piping that kind of CO2 over the Sierra into the San Joaquin basin is not economically viable. So if we had our own in-state captured CO2, that starts to look attractive to a lot of operators in the San Joaquin Valley.

Eighty percent of our emissions sources are within 50 kilometers of a potential site. EOR operations do recycle CO2 because they buy it and they want to optimize its use. But even with that, they get 30 to 60 percent of the injected volumes left underground. So they do sequester even when they're in operation and obviously that could change with time if they were to become true sequestration sites instead of EOR facilities.

And the demand for EOR could actually result in about one million tons stored. These are estimates that were made by Advance Resources International with a U.S. Department of Energy grant.

I want to jump now into the technical components. Something odd happened to my font there that use to sit perpendicular, but it says, “Components of technical readiness” over there on the left.

I'm going to stick with the technical readiness issues and not say much at all about the economics and the statutory and the regulatory readiness because, again, those issues will be covered by other people this morning. And as capture technologies also, you'll be hearing another talk about that.

So the components of technical readiness that we need to be concerned about are transportation, surface issues for plant and well siting which is very much within the purview of the Energy Commission, and then subsurface elements which is kind of the unknown that is creating a lot of public perception issues and insurance risks, liability issues and so on for CCS Technology.

So I'll touch a bit on risk management, site characterization and certification, monitoring verification and remediation and mitigation. And each of these issues has a chapter devoted to it in the AB 1925 report.

First, pipelines, CO2 pipelines are very mature technologies. I mentioned they're all over the U.S., over 3,000 miles of CO2 pipeline delivering over ten trillion cubic feet of gas. A regulatory framework exists in California. We do have some pipelines here in state. The Office of the State Fire Marshall oversees those regulations. An experienced work force exists.

And importantly, the CO2 EOR Industry which pipes all this CO2 reports no serious injuries or deaths associated with CO2 pipelines. So it's a very mature safety technology. There are automatic waft valve closures, spacings regulated by the U.S. Department of Transportation. A lot of these pipelines have telemetry for 24-hour real-time monitoring so if there is a leak, if they're compromised for some reason, which is apparently quite rare, even so, they immediately isolate that piece of the pipe that's breached with the block valves and they go out and they fix it and they know about it pretty much right away.

In Future Gen, that was the big federal project to do a combined IPCC/CCS project, since been canceled, but they did the environmental risk assessment and they identified not subsurface leakage as the biggest risk, but actually pipeline leakage as the most significant hazard in that assessment.

Insurance of facility siting, the interesting thing that came out of AB 1925 report in discussions with the Energy Commission citing the Transmission Environmental Protection Division. So even though they're doing a surface siting, it's clear that they have to think about CCS when they do these permitting.

The comments they made were addition of CCS to new or even existing power plants has potential effects on regulatory frameworks such as CEQA and Warren/Alquist for siting the new plants or even retrofitting existing facilities. Since the Energy Commission is the CEQA lead agency for -- or will likely be the lead agency for CCS associated with power plants, this aspect needs to be included in any follow up studies done in preparation for the 2010 report. And those will be happening fairly soon, we hope. So those discussions will be. So again, any input will be appreciated.

Subsurface technical readiness, we have a lot of mature technology and a lot of experience with analogs. Analogs include natural CO2 reservoirs, CO2 storage through EOR, natural gas storage and then CCS pilots and early commercial projects. And again, a lot of the pilots have been done by the Regional Carbon Sequestration Partnerships including WESTCARB.

Oil and gas industry is where most of the relevant technology rests. They have excellent subsurface characterization technologies and they provide a lot of relevant knowledge and experience to the plan's technology. I've got a couple pictures here from two of the early commercial scale, pilots for commercial projects, Sleitner in Norway which is off shore and Weyburn which is up in Canada where they're injecting into a carbonate reservoir.

The insurance companies have started to take notice of CCS and have termed their risk tools to developing risk profiles. And when you look at, for example, environmental risks, you note that the highest risk is actually during injection. So not out at those time scales which actually make people nervous, but actually within the first 30 to 50 years when you're actually doing injection.

The key to risk management is ensuring the site characterization and monitoring data to give us confidence in our predictive modeling. And you can see at the bottom, we calibrate and validate models over the life of the project. And so, when we're out at those long time periods, we have confidence in our models and the risk goes down and peters out over time.

Risk perception and awareness is certainly going to affect rates of adoption. Surveys here in the U.S. and in Europe have repeatedly shown that the public is concerned most about harm or damage from leakage of CO_2. They're also concerned by accountability and stewardship issues over these extremely long time scales.

Other risks that have been identified probably more by scientists than the public, are damage from induce seismic or brine migration or pressure pulses and saline formations and climate change risk from cumulative slow leakage of CO_2 back into the atmosphere. In other words, the thing is going to just keep leaking slowly over time. So in 200 years, you've lost a significant amount of what you put into the ground, what was the point of doing it. So we have to find some way of verifying that the stuff has stayed in storage.

It's important, I think, to note in particular because scientists have a really bad habit of talking about pools or bubbles of CO2 underground. And some of the public surveys I read, people really believed this, okay. These are not actually pools or bubbles. The reservoir rocks are sandstones and the typical sort of reservoir sandstone is shown there by that red, very solid blob of outcropping sandstone. They have high permeability, but it's all in very, very course spaces between the grains. So it's not like we have a cave underground that this big pool of CO2 is sitting in it, that if it's breached, it's all going to suddenly burp out and be a major hazard. This stuff has to -- it, in case of a leak, has to wind its way out from between all of those little sand grains where the stuff is actually sequestered as shown on the lower right there.

What is in those pore spaces before the CO2 comes in is saline water or brine. Even in an oil field, a lot of the pore space is occupied by water, especially in an depleted oil field, it's not occupied by oil. And the salinities here can be from one-third up to four times seawater. The CO2 displaces that brine, but can also dissolve in it and react with the sand grains. And we call those sorts of things, it's a secondary trapping mechanism. So the stuff is held in the rock pretty tightly.

The sequestration reservoir has to have very specific attributes. Injectivity means how easy is it to get the CO_2 into the rock and displace those subsurface fluids. Capacity is how much CO_2 the rock will hold and this includes dissolve phases or mineral phase, phases created by the action. And integrity which is the ability of the sealing locks to keep that CO_2 in the reservoir and also to make sure that there aren't any leaking orphan wells or falls on the site.

So again, it's very important that the data during site characterization and that's collected by monitoring through the life of the project are verifying reservoir performance so your predictions are good.

Monitoring must track CO_2 migration, detect leaks and verify storage. There are a number of mature techniques that are available. This is from the CO_2 capture project and it just illustrates all the different technologies that can be used to track CO_2 and to monitor for leakage.

Remediation and mitigation addresses what to do in case of a leak and, again, these aren't technologies that we have to invent. They already exist. They're used by the Natural Gas Storage industry and by the oil industry. And again, this just lists, for example, I don't know how well you can read that, but for (e), if CO_2 escapes by a poorly plugged or abandoned wells, you can go out and replug that well and put in some CO_2 resistant cement.

It's important also to realize and remember that CO_2 is not really a toxic substance unless it's present in hugely high concentrations. And if it reaches the surface, whether or not it's a hazard depends on the concentrations and on atmospheric conditions. For example, in Mammoth Mountain, you see signs all over the place, CO_2 hazard area. This is magmatic emissions that build up into soils and they do cause tree kills. And they can also and have killed humans and animals when the CO_2 gets trapped in low places like snow caves and you have stagnant atmospheric conditions you can get buildup to lethal percentages.

In the tree-kill areas, the soil's CO_2 is on the order of 80 to 90 percent. However, in Italy, people live around fumerolles that give off 150 tons a day of CO_2 with no negative effects at all. Crystal Geyser, you see a family playing around this CO_2 geyser which was created by an abandoned exploration well that penetrated a natural CO_2 reservoir and it geysers that CO_2 and water and no one has ever been harmed by that.

Two just very quick summary slides. You'll be hearing a lot more about this. Regulatory means the technology and knowledge exists to inform the regulations. A demonstration and early projects are needed to provide test cases. And given the differences, I think it's very important that we have a regulatory framework that's flexible, that can be streamlined and that is predictable and consistent across the different types of reservoirs and sources that it's going to need to be -- to regulate.

Statutory needs, given the long-term nature, again, this just sort of reiterates things Martha already brought up. Long-term stewardship is a big one. How do we protect people and the environment in the long term and assure that we've had climate change mitigation over the long term. There are ambiguities in pore space ownership. Liability limits have to be defined and how they follow ownership. And we have to address issues that arise from any kind of a CARP and credit or cap-and-trade system that is put in place.

So just to summarize, there is a large geologic potential and large point sources and reasonable proximity to those sites. And several options look pretty good as a first cut. Out-of-state power suppliers or coal plants is the most economic way to do it in the power sector. CCS with EOR or CCS with ethanol where you might get double carbon reductions.

CCS is technically ready and we've addressed risks in similar -- or industries that have to manage similar types of risks. And then, just kind of a laundry list here of needs and next steps, some of which we will be addressing in the 2010 report.

It's really important to have demos in early projects so we learn before we have a full-scale mean for this technology. We have to have the regulatory and statutory frameworks in place to enable these early projects. The economics of capture has to be improved. We have to understand how to develop a pipeline in the structure and we have to understand the effects of CCS on power costs and future energy portfolios for California including things like the cost of generation models that the Energy Commission uses.

We have to identify the ramifications of different regulatory and statutory options and we have to define protocols for CCS site selection operations and closure. So with that.

MR. MYER: Thank you very much. Any questions for Elizabeth?

PRESIDING MEMBER BYRON: Well, I think Mr. Birkenshaw may have one as well, Birkenshaw may have one as well, but I'll note that it is interesting that in just a couple of years, the conclusions have changed significantly given the momentum towards the need for carbon capture sequestration. And, of course, that's mentioned in your presentation. Would you care to elaborate on that at all?

MS. BURTON: I think for us it's very good news. We -- I think at the point of the 2007, we're a little more vocal about pushing it. And it was, you know, sort of a conservative approach in the IEPR toward the technology at that time which was justified based on economic considerations and so on.

But what we could see looking from the WESTCARB and a scientific viewpoint is hey, this is the technology that really isn't that far from being deployable and, I think, you know, we were maybe more excited about it, but might have been merited by regulatory and statutory issues. But I'm very glad to see that things have moved so quickly and that it looks like policies, statutes, regulations are going to now follow quickly to enable the technology.

PRESIDING MEMBER BYRON: Good, thank you.

MR. BIRKINSHAW: Yeah, I just have one question for you, Liz. You showed a picture of Mammoth Lake and the warning signs and the tree kill. Can you talk a little bit about the mechanisms that lead to that kind of a situation, that kind of damage to the environment? And elaborate a little more about the distinction between that kind of situation and the way in which CCS might be implemented here in California and the risk associated with that situation, developing in context with CCS.

MS. BURTON: I am not sure how much I can get into this in 30 seconds, but I'll give it a go. With the Mammoth Mountain situation, the CO_2 is vented from volcanic emissions from a magma source that's fairly deep and it causes a lot of seismic activity and I think everybody's kind of familiar with the whole kind of environmental tenuous situation that really from a geological standpoint exists at Mammoth.

The CO_2 leaks out of -- is a volcanic emission. All volcanoes do this to some degree and it builds up in the soil in the case of the tree kills. Again, they're only very isolated places in Mammoth where that does happen. It's not pervasive over the whole extent of the magma chamber. And when it reaches a certain critical threshold, then the trees die. We are doing some studies of how we can do aerial surveys to pick up plant stress early in the case of a leakage.

In terms of the physics and chemistry of a potential CO_2 leak, it doesn't look at all like the sort of process that is happening at Mammoth. So there are fundamental scientific differences in the way those leaks happen and what we would predict with a CO_2 reservoir. So in the case of a magma, you've got something that's come up and there's not necessarily any kind of a cap rock to prevent those emissions from coming up. The placement of the magma creates a lot of faults and fissures that are natural leakage pathways into the overlying soil.

With a CO2 reservoir we want to make sure we're not in that kind of a situation, where we have a good ceiling cap rock over our reservoir. So does that kind of cover your points as briefly as I can for now?

MR. MYER: Thank you very much. Thanks very much, Elizabeth. We'll move on, then, to the next presentation which is an overview of CCS legal and regulatory, institutional issues and approaches being pursued federally and by other states by Craig Hart who is counsel in Engineering -- Energy Infrastructure, Climate Change and Technology from Alston & Bird. And thank you for making the trip across the country.

MR. HART: Good morning, everyone. I'm going to cover CCS financial, legal and regulatory barriers. I'm going to focus on the legal and regulatory, but I'm going to start off by pointing out some of the cost curves for CCS. This is for the electricity industry and I'm simply going to start with this to show you that the cost matters and it matters if you're developing legislation or regulation in this area.

This was developed by Baker & McKinsey. They're estimating there are a dozen different studies with different numbers. So this is really only a -- to give you the magnitude. That by 2015, they expect the cost to be somewhere in the 60 to 90 Euro-ton range for a demonstration phase project. And what they're hoping to get is to cut that in half or better over time. But as we stand now, for demonstration projects, whether they're commercial scale or not, that the cost is quite high, in the up to 90 Euro-ton.

And the cost is allocated primarily to the capture piece of this. The storage piece, the monitoring, the verification part are relatively insignificant in comparison. And that also will matter as to how you design legislation. It certainly is impacting what's happening at the federal level, as I'm about to go into. However, the legal issues really are at the second, in the second tier, in the storage tier because those have to do with the land and that is where your liability will be. And the cost of legal compliance are not reflected in these numbers, I should add.

Okay, the glass slide of economics, you know, there have been a dozen or so studies with different numbers. There are a great deal of variables as to what influence these numbers. So, I'm presenting them with, you know, with the idea in mind that -- don't take the numbers as fixed. They're -- they will change and they will change dramatically as we start to build large field demonstration plants.

Okay, so I'm going to start with the federal, what's happened at the federal level on CCS and most of what has been done at the federal level has been deemed as the economics. It's been an effort to get the costs down, or to help companies that are undertaking CCS in the early stage, to get the costs down. So we've had a tax credit that covers both, permanent sequestration in EOR as well as saline and other formations. We've got qualified energy conservation bonds that can be used for CCS activities. We've got $3.4 billion in R&D. And we've got money going to the DOE Regional Carbon Sequestration Partnerships which were alluded to earlier and I'm going to discuss a little bit here as well in relation to liability.

That money in the stimulus funds don't go, though, to dealing with any of the property and liability issues. So most of what the federal government has been dealing with are the economics.

The property and liability issues will be primarily in the ballpark of the states because land and property law and tort law are driven largely by state law.

I'm not going to go through all of these points in what is meant to be an overview talk, but we will get into a few of them. Before going into the individual issues, what I want to point out to you is we do have some empirical data on liability issues from the Phase 2 Regional Sequestration Partner, the DOE effort.

We did a survey of 19 of the 24 projects in the Phase 2 of the DOE demonstration projects. These were the small scale injection projects. They ranged from 34 tons to upwards of 100,000 tons. And what we found is the liability issues came up in a majority of the projects. And if you look at the table, you'll see that for projects over 2,000 tons and above, a majority of all those projects reported legal issues relating to liability. They were significant enough that they actually had an impact on either the scheduling of the time or cost of conducting R&D.

Now, this study was really looking at what the barriers were to CCS R&D as opposed to the barriers to doing a large scale project. But the point is is the liability issues do matter and based on what little empirical data we have, we can see that they affect a majority of projects even in fairly small scale injection models.

These were how some of those liability issues were dealt with. In six of the 19 projects, liability was assumed by a project party. In five of the projects, five of the 19, liability was not raised in the negotiations but it ended up being essentially not allocated or accepted by a party. At the time that the study was done, two were under negotiation, one project was canceled in part as a result of liability issues, three declined to comment, two too early to know at the time of the study.

But one thing I want to point out to you is that of the 19 data points that we have, 14 of them have an EOR connection. Twelve of the projects were in EOR fields and two of them -- were actually EOR projects and two of them were not EOR projects but they involved an injection in the middle of an EOR field. And that's significant because what we found in doing the study was that EOR operators were quite comfortable with liability. They'd been doing this for a long time, they understand the risks of injecting CO2. And of the projects in the top two tiers, the six where liability were assumed by a project party and in the five where it wasn't raised, those are EOR projects.

So the data shows that if you have, at least in the Phase 2, which are small scale, where you had EOR, liability was matched. Now we're doing the Phase 3 study and we're going to be looking at different applications, but I think the take-away, at least the way I've interpreted this, is that if you have EOR, you were going to have a tremendous amount of comfort in that community for doing this and also support from a financial and legal point of view in trying to address those issues.

Now, having said that, most of the storage capacity is in saline. It is, you know, I think it's 85 percent approximately of storage capacity is in saline. So if these liability issues don't transfer into the saline sphere, we need to look at how to deal with liability in the saline area where there's no EOR connection.

Okay. Now, moving to -- I'm going to move quickly through the remainder of the federal and then on to the states. The EPA has issued Class 6 Proposed Rules for injections. And this is only intended to prevent any damage to safe drinking water aquifers. They have proposed a number of provisions in this area, including financial insurance which does go to liability. David Albright is going to speak about this in more detail, so I'm not going to cover this.

However, I will note that it leaves the potential for RCRA and CERCLA liability depending upon whether that CO_2 that is being injected has other elements in it. Okay, CO_2 alone, not a contaminate per se, but if there is something in it that is hazardous, that could cause RCRA and CERCLA liability and the panel will get into those issues a bit more.

What's important to note here is this only deals with drinking water. It doesn't deal with other issues, it doesn't deal with liability outside of the drinking water context.

The Waxman/Markey Bill. This is a draft Bill released last week. This also contains a number of provisions that will implicate liability. There is a financial insurance mechanism, but again, it's limited to drinking water.

There will be a study that will look at legal frameworks and it will look at federal, state and global legal frameworks covering transportation, sequestration, all aspects.

There will be -- EPA has been asked to coordinate with DOE to present a comprehensive strategy to address legal and regulatory barriers. We don't know what that's going to look like. The states have, I don't want to use the word premecy in this area, property law is state law.

So whatever the federal government tends to do, at some point they're going to be making recommendations and I think they're going to face a barrier in that the federal government can't legislate or would be unwilling, in all likelihood, to legislate away state property law. There is going to be a very significant role for the states here.

Also this Bill includes very significant credits and financial incentives. And again, going to that financial piece, I think you can still see in Waxman/Markey that there is a significant amount of effort being paid to the economics. And the federal government is going to be better suited to dealing with the economics than they are the liability issues which will remain a state area.

Senator Bingaman has issued a draft Liability Bill. It's due for markup later this week. That will pick up liability for ten projects, up to ten projects. The projects must be one million tons or greater per year in a geologic formation. Any industrial source will qualify. They are intended to be fully integrated system. So in other words, not the kind of test injections we saw in Phase 2, but more the full scale, commercial projects that we're seeing industry propose and also in the deal with Phase 3.

They subject for the projects that apply and DOE would then accept them. They have to demonstrate that they have met strict operating and post-closure requirements. There'll be a financial insurance mechanism. They will, in fact, pay for this coverage through an indemnity fee that's been -- which we don't know what the details will be, but if this Bill is to be passed, presumably there's going to be a rule-making regulation that would operationalize this language, that it's the net present value of the expected payouts under the Bill for liability. And the liability that's being covered is property and tort indemnity starting ten years after the safe closure and of the injection and the plume has reached equilibrium.

So what you're seeing is a proposed Liability Bill for ten projects. This could very well go and support Phase 3 of the DOE projects and it could be for other things, too, it's open. But again, it's almost an experiment because ten projects, you know, we already have upwards of seven projects in the DOE Phase 3 and if we want to see this technology really incentivize and start moving down the buy-down curve, we need to see more aggressive approaches to look to liability.

State actions. We are seeing activity in the 30 plus states. The story is most interesting at the state level. And the legislation that we're seeing is -- ranges in a number areas, but these are the main ones: siting, operation closure requirements, pore and CO2 ownership, financial insurances, financial incentives in some cases where states are getting in and looking at the economics, state assumption of liability and usually after it's -- again, after a ten-year period, jurisdiction among regulators within the state who has responsibility, and a number of states of doing work study groups.

And here's what several of the leaders -- and these are the -- I'm going to show you two slides of states that have an active legislation. I'm not going to show you pending legislation. There's 20 plus more states that have legislation pending.

Wyoming has been one of the most aggressive. They have gone ahead and defined pore and CO_2 ownership. They have specified that the owner has liability for injected -- that the injector of CO_2 has liability for that CO_2. They have developed the unitization law, similar to what's used in the oil and gas area, for unitizing and aggregating subsurface formations for CO_2 injection. They've also clarified that the mineral estate is dominant over the pore estate. So Wyoming has done quite a bit of thinking. Their philosophy has been we don't want to move the sticks around among players, but we definitely want to see this technology move forward.

Montana has been another early mover. They have defined pore ownership. They also have a liability transfer mechanism from a project party to the state after, I believe, ten years as well. Mississippi has a business income tax on carbon.

North Dakota has done a lot as well. Again, they've taken on -- they've defined pore ownership, they have a liability transfer mechanism to the state, they have a unitization law, they have a regulatory framework and they have subsidies and a fee-based storage facility fund which is a financial insurance mechanism.

And I'm not going to go into detail with the remainder of these states that have tax legislation, but I'll note West Virginia has also gone ahead and defined pore ownership which is particularly significant. And Kansas has a financial insurance mechanism.

So it's those, from a personal perspective, going back to the things that states have done, I think the pore and CO2 ownership, financial insurance and state assumption and liability are three of the most significant things that a state can do.

That's the conclusion of my introductory remarks. We do have a panel, we're going to have an opportunity to get more into detail. I'm going to turn this over to Larry at this point.

MR. MYER: I believe --

MR. BIRKINSHAW: I have just one --

MR. MYER: -- entertain a couple of questions just sort of from an introductory perspective before we get into the panels.

MR. BIRKINSHAW: Yeah, I have just one question. You mentioned that the Feds generally reluctant to interview in a state property law, but that the Bingaman Bill seems to set up a number of mechanisms for these ten projects. Do you envision that there'll have to be changes to state law to -- in the places where those projects are located?

MR. HART: No, I think they're going to be careful not to tread on the toes of the states. I think that it's extremely significant that they have proceeded like this. And I think they've done it carefully. I mean, they've limited it to ten. They've retained authority of the DOE to select those ten. They've subjected them to -- those ten will have to comply with a number of very strict requirements. And I think all the federal government is doing is saying, we'll indemnify anyone who's quorumed for property and tort, loss of life and so on, if those issues were to arise, under very -- but within a very strict set of guidelines.

And I think for the federal government to go and take that kind of responsibility for that potential liability doesn't -- that's more of a contractual matter. There are other examples of where the federal government does, indeed, indemnify parties and usually in the defense area and so on, here, they have contractual relationships. So they can do this. And arguably this is research or demonstration, commercial demonstration, in the public interest. And they've gone ahead and decided to propose this legislation.

I don't think, though, let me add, I don't think though, this, in anyway, this is only ten projects. I do not think this in anyway lessens the importance of this as a state issue, all right.

PRESIDING MEMBER BYRON: Mr. Hart, thank you, a good overview. I sensed, maybe not surprise, but when you indicated that about 14 of the 19 of the projects surveyed were associated an enhanced oil recovery, they were able to manage the liability issue. Isn't that really because they have responsibility for the wells that they're currently active in anyhow and so the added responsibility or added liability of the CO2 is really a small addition for them?

MR. HART: I agree. I think I was surprised and others were surprised, even some who were close to these projects. The EOR, the fact that EOR is going on, the fact they're comfortable with injecting, the fact that they have a long history and they know what the potential liabilities are made EOR operators very comfortable in taking on additional risks.

They also had the economic infrastructure in place in order to go ahead and support research by national labs and universities on their fields. And without getting into too many details, you know, the EOR operators provided a great -- they were great partners in these projects. They provided needed support across a range of activities, whether it was unitizing land or dealing with property rights owners whose consents were needed and so on. They were actually quite significant in moving the ball forward in Phase 2.

I think the Phase 3 projects are not going to be quite as focused on the EOR although several of them do and those, you know, we won't have really empirical results for, well, I think we'll have some preliminary ones in the next few months. And early next year, we'll have a report out.

PRESIDING MEMBER BYRON: Good. I suspect the panel will get into the subject a little bit more, thank you.

MR. MYER: I think we can now move right on into the panels. So I'd like to have the panelists come up to the table. And as they do so, I'll just give a couple brief introductory remarks.

We might have to do a little shuffling here. I believe we have six -- we need six chairs over here. And so, as they're coming up, the focus of this panel is to ask for stakeholder opinions and input on the issues of institutional issues, liability and regulatory aspects.

And so what we have, then, is folks who have volunteered to do this and I'm very happy I was able to do this. Susann Nordrum from Chevron will speak to the oil refineries perspective. We have Mark Nelson from Southern

California Edison representing an investor-owned utility. We have Tiffany Rau from the HECA project and hydrogen energy to -- representing unregulated power and CO2 HECA project developer. And we have Mike Stettner from the Division of Oil and Gas and Neothermal Resources, California's Conservation, representing their perspective. And we have David Albright from the US EPA Region Nine. And then we have George Peridas from the Natural Resources Defense Council as well.

And so, at this time, I think I'll turn it over, then, to Greg -- Craig, who is the -- who will moderate the panel discussion.

MR. HART: Thank you, Larry. I'm going to suggest we -- the format that we're following is that each of the panelists are going to spend several minutes, five or so minutes, giving an overview from their perspective. And then we want to open this up for any questions and for active discussion.

So, I'm going to ask, starting with Mike Stettner, we'll just move from you down the row, if you'd like to lead us off, please.

MR. STETTNER: Good morning. Well, I'm going to just jump right to the -- I had a PowerPoint, but I'm not --

UNKNOWN SPEAKER: Mike, it's up.

MR. STETTNER: I might just follow it.

UNKNOWN SPEAKER: Just to tell you, Mike, it's advancement.

MR. STETTNER: That's okay, I don't need it. I'm going to just jump to the last slide of my PowerPoint, and that's to emphasize that the Division of Oil and Gas and Geothermal Resource has been regulating oil and gas wells since 1915 and water flood began in the 1940s and gas soon after. This one's labled, right?

So we have about 60 years of experience or more, 60 plus years of experience in regulating underground injection, whether it's fluids or gas. I just wanted to make -- emphasize that point.

Our current authority is regulated to the fluids that are associated, imminently associated with oil and gas production. And that includes EOR and water disposal. And it can go in -- it does include zones that are not oil and gas bearing zones. But the fluid has to be imminently associated with oil and gas.

And as an analogy, if you permeant a -- if a cogeneration facility is permeant and the steam from that facility is used in an EOR operation, the fluid that is associated with that power plant, that co-gen, can then be injected into a water disposal well under our purview.

If you have a cogeneration facility where the steam is not used, you know, an oil and gas operation, we don't have the authority over that fluid. So that's a fine point, but we do extend our authority to those facilities if it's associated with oil and gas operations.

And I had another point I wanted to make on that, on the EOR liability. I appreciate what you were saying there, Craig, but it came to my mind that on EOR liability, we're -- well, we had eight pilot projects in the state. Some of them have been very successful. But I may go out on a limb here and say that the liability for EOR doesn't include the facilities. And so it may be inadequate at this time.

Our authority for liability only requires the bonding of the wells. And that will -- we would incorporate that into any regulation if we ever go that direction, for CCS. We would only be involved in the storage part of CCS and we are willing to adopt those regulations. There have been efforts in the past, but they just haven't proved fruitful.

But I think that's one -- that liability issue with EOR doesn't include, for our case, it doesn't include facilities. So that was something that may have to be -- that's an issue that may have to be addressed at a later time.

MR. HART: David.

MR. ALBRIGHT: Okay. I'm David Albright. I'm the manager of the Ground Water Office at EPA in Region Nine. So we're one of ten regions. And I'm going to be speaking just briefly about EPA's proposed rule for geosequestration. Craig spoke about this a little bit and I was just going to highlight some of the key issues that arose in the public comment period.

So I wanted to start just by saying that as people probably know, when we're at this stage in rule making which is between the proposed rule and the final rule, we try to refrain from predicting or projecting what the outcome will be on any particular issue in order to let the process run and to allow our decision-makers the first ability to make those decisions they need to make in crafting the final rule.

The other point that I wanted to make initially was that certainly EPA recognizes carbon capture and storage as a key tool in climate change mitigation, but this particular rule that I'm speaking of is just a rule that will be promulgated under the Safe Drinking Water Act and the focus on the Safe Drinking Water Act is the protection of underground storage -- underground sources of drinking water.

Certainly, there's a lot going on at EPA and in Congress pertaining to carbon capture and storage, but this particular rule is just about injection and the protection of underground sources of drinking water.

And finally, as an opening point, the rule does not propel carbon capture and storage. It only addresses the requirements that would be imposed whether its injection of carbon dioxide for geosequestration purposes.

So one of the -- the first of the four issues I wanted to talk about briefly is post-injection site care and closure. And in the proposed rule, we proposed a fifth year time period for post-injection site care. And what that means is after the cessation of injection at a site, there would be a 50-year time period when that site would need to be monitored to track the travel of the CO2 plume and the pressure response and subsurface to see that that -- that the CO2 is immobilized and that the pressure had dissipated and built up in the formation.

We got a lot of comments, certainly, on that. Fifty years is too much, 50 years is not enough. Some people want a performance standard in place. Actually what we had proposed was a 50-year time period but with some flexibility whereby a regulating agency, either EPA or the state, could lessen or increase that time frame depending on what the modeling and the monitoring was showing. We certainly got a lot of comments in that area and I think it's an issue that some people may wish to discuss.

The second issue that I wanted to bring up was financial responsibility and liability, something that Craig also was eluding to. Financial responsibility in the underground injection control program refers to an owner/operator having at the beginning of this project funds set aside or confirmed available to fund the well that's being constructed and to abandon it properly.

In the case of geosequestration, the financial responsibility of what we're talking about is obviously funds to plug and abandon the well, but also to conduct the post-injection site care, any sort of remedial or emergency response that would be needed in association with that well as well.

We did not propose any specific requirements, only a more general requirement that operators have the financial responsibility in place when they have embarked on these projects.

In terms of liability, the proposed rule really did not address liability. We touched on it and we certainly got a lot of comments suggesting that the owner/operator perhaps should not be the one who has long-term liability. And that, by default, would otherwise be the situation with injection that occurs now. The owner/operator is the one who holds liability in the long term.

The third area I wanted to briefly mention and one that is particularly relevant, I think, in California is the conversion problem, Class 2 injection which is long gas -- past oil recovery and past gas recover to Class 6 which is the new class of oil that EPA has proposed, creating with this proposed rule.

Class 2 injection, obviously, goes on right now in California. There are about 30,000 Class 2 injection laws in the state. It's expected that a lot of initial projects where there is geosequestration will be done in/on gas fields and may start out as enhanced property projects.

The question is how do you establish when the well is no longer a Class 2 well and becomes a Class 6 well that is -- specifically doesn't (indiscernible) for geosequestration. You create a bright line and some people felt like there's really no difference and we should just allow there to be a seamless transition from Class 2 to Class 6.

There are also issues about when you're drilling a new well, if you're drilling it as a enhanced recovery well and it's going to become a geosequestration well, would you impose specific requirements on that initial drilling even though it's a Class 2 and there are regulations that exist on government Class 2 wells.

The fourth and final point that I wanted to make about the comments that we got on the proposed rule has to do with primacy. This refers to a situation where a special entity, underground injection control program, EPA has delegated to state agencies the responsibility to implement the federal program. We do have primacy in place now with the UIC Program. In the State of California, they have what's called 1425 Primacy. This is a section of the Safe Drinking Water Act and it's just for Class 2 wells. So in California right now, the Division of Oil and Gas overseas Class 2 wells and then EPA has responsibility for all other classes of well.

I think this is an interesting topic of discussion because the Class 6 wells would be part of 1422 Primacy. That's the other section of the Safe Drinking Water Act, dealing with primacy. And right now, the State of California does not have 1422 Primacy. They have primacy only for Class 2 wells, as I noted.

So it is a key issue. Obviously, EPA knows that many states are going to want to take delegation of Class 6 injection wells and there are a few other states that have this situation where there's Class 2 only primacy right now and the Agency is looking at how that would be handled. We certainly got plenty of comments suggesting that we should allow Class 6 primacy for states to take Class 6 primacy as a stand-alone without respect to any other classes of injection wells.

So those are the four areas I wanted to highlight. The last thing I wanted to say is that EPA is working on a Supplemental Federal Register on this. Some of you may have heard about this. It's a so-called Notice of Data Availability. And I expect that we'll be issuing this in the next month or so. This will be an opportunity for the EPA to get some additional information about carbon sequestration out based on the research that's been ongoing and to solicit some further comments on approaches for handling geosequestration. So I suggest that people look for that and certainly comment to EPA when that does come out. Thank you.

MS. NORDRUM: Hi, I'm Susann Nordrum. I'm with Chevron Energy Technology Company. I am leading our team that does research on carbon dioxide capture and sequestration, and more recently, working very closely with our facilities in California to work through how we're going to be able to comply with the requirements of AB 32 as the details of that program emerge.

Just had a few points we wanted to make on CO2 capture and sequestration. I think the word “liability” has come up once and twice and certainly as a business in California, that's something we need to understand how that's going to work. It needs to be addressed. You know, we feel that there are cost effective financial mechanisms like letters of credit, bonds or third-party insurance. Or there could be a public/private funded entity. I think Craig mentioned some of the other states are working towards that. So I think that's, you know, really a prominent issue that we need to take care of in order to have certainty going forward.

Another issue is that we don't think CO2 should be regulated as a waste or a pollutant. It's currently a commodity in the market. People pay to get CO2 to do enhanced oil recovery and also as an industrial gas for things like beverage industry and dry ice. So you'd have a really, I guess, huge amount of complexity that could emerge and would basically just get in the way of solving the problem. So you want to just go forward and enable carbon dioxide capture and sequestration without burdening it with additional regulations beyond, you know, kind of the caps and things that will be under AB 32.

The third point is and I think that this has also been made, is that the petroleum industry really has had a lot of experience and expertise in the subsurface. And, you know, sequestration of carbon dioxide under the ground has a lot of ventral analogs and certainly with the enhanced oil recovery operations, that the idea of injecting CO2 into the deep subsurface is not some brand new step-up thing, but really an extension of activities that we already undertake.

And then finally, maintaining the safety and environmental integrity is the highest priority of Chevron. For every project we do, CCS or drilling or building a refinery, we take it very seriously, evaluate it carefully. And we want to make sure that it's safe before we go forward. We wouldn't do it if it's not safe. Thank you.

MS. RAU: Hello. I'm Tiffany Rau and I'm the Policy and Communications manager for Hydrogen Energy International here in the Americas. And as has been mentioned today already, our company is proposing a power plant with hydrogen fueled power generation and 90 percent carbon dioxide capture and sequestration.

We will deliver 250 megawatts of base low power to the grid and sequester over two million tons per year for enhanced oil recovery. We're also, Southern California Edison is studying the feasibility of the project and the feasibility of their participation therein.

The Hydrogen Energy California Project which is kind of referred to as HECA for short is considered an early mover commercial project.

And I just wanted to say, we're looking at the whole phase and the whole value chain of putting together an integrated power plant with carbon capture and sequestration for enhanced oil recovery. And so not only do we look at and are working within the CCS regulatory framework development, but also the whole power structure, power off-take piece of it for purposes of providing low carbon power to California.

And from our perspective, we believe that sequestration for enhanced oil recovery that's located wholly within a partially depleted oil reservoir is resolved and clear. We don't see any regulatory or legal uncertainty that gives us pause from going forward.

With the exception -- and I'll say with the exception of long-term liability which keeps being mentioned, this is -- when I say long-term liability or what I like to call stewardship, we're talking post-closure. We believe there's a certainty around not only site characterization, but during enhanced oil recovery and injection operations, that it's clear what would need to be done and where the liabilities exist.

The reason why the liability needs to be resolved and addressed in the long term is simply because private entities don't last in perpetuity. So there -- it has to be addressed ultimately. But we don't feel that it's a barrier to entry and in some cases I feel like maybe it's an excuse not to deploy CCS. So kind of we're -- as I said, we're an early mover. We're proceeding. We feel that in the interest of climate policy, Congress or perhaps the states will address with the issue post-closure liability in a reasonable manner. And that's worth proceeding.

And similarly, while we agree that trespass and mineral rights and ownership with pore space may arise relative to saline formations, we don't see them as a concern for an oil and gas fields, especially in an existing, very fully characterized oil reservoir such as Elk Hills in Kern County which will be the destination for the CO2 from a HECA Project. And not only is it a very well characterized formation, but the ownership if very clearly defined.

So we would ask that the CEC to recognize the distinction between injection in saline versus injection into oil and gas for enhanced oil recovery purposes and not go into the complicated rule making procedure that might impede early movers from going forward.

And I also wanted to point out because I know there are some risks associated or perceived risks associated with CO2 transport and pipeline. The HECA Project itself, all the linears for that project are within five miles of the site, including the CO2 pipeline. So that isn't an issue that's causing us from going -- keeping us from going forward either.

It has been mentioned a bit that Hydrogen Energy has recently signed on to a multi-stakeholder letter which includes a number of NGOs, oil companies and utilities that will support the EPA rule making process for sequestration governing CO2 injection for both EOR purposes and ultimately long-term storage. The recommendations acknowledge that EOR and storage can be achieved simultaneously. I think it's important to be paying attention to the NODA that the EPA representative mentioned.

And part of the purpose of today's workshop is to support -- well, it is the purpose, is to support the IEPR, the 2009 IEPR relative to CCS policies to achieve AB 32 goals. And as Liz pointed out, the 2007 report concluded that it's unlikely that plants using CCS will be available to contribute to AB 32 and the 2020 Bills. And we believe that that U.S. Cert, that's no longer true and certainly with respect to power plants utilizing CCS for EOR and we would look for the 2009 IEPR to recognize that.

We believe that HECA Plant will make a real contribution to 2020 AB 32 goals. Saying that, however, I do want to make it clear that if we're -- the HECA Project, even though it will make, we think it will make a difference in meeting 2020 goals and demonstrating the viability of CCS for post-2020 Bills, we don't necessarily expect for the HECA Project to play into AB 32's cap-and-trade type of the scheme. Instead it was the value of the product being in the low carbon base load attribute of what the plant would be producing as well as the technology demonstration. This is all being worked through at the PUC.

So as we look to a permit and go forward with the project, you see the enhanced oil -- the CO2 injection being regulated by a Class 2 permit. And then for compliance with SB 1368, there'd be a sequestration insurance plan submitted per the law that demonstrates that sequestration is -- or long-term storage is economically and technologically feasible.

And so I'll just jump to what is it that we think we really need since it's probably more in Mark Nelson, to my left here, from Southern California Edison, will go into what the utilities think that they need in order to go forward and ultimately either invest in CCS technology or procure power from CCS enabled plants. And we would like to see CEC and PUC work together for an incentive structure or at least very clear cost recovery certainties for utilities and generators that invest in the CCS enabled low carbon power. That is where I'll stop.

MR. NELSON: I'm Mark Nelson. I'm the director of Generation Planning for Edison. I've been sort of shuffling notes here on the fly to fit in. It's always hard when you're further down the batting order.

For the utilities, especially in California, CCS is a fairly logical continuation of work we've done. In the 80s, Edison built the first integrated gas location combine cycle of Coolwater. So carbon capture and storage really is a follow-on to that.

Traditionally, the investor on utilities are tools of public policy and do move ahead on issues like this, think, I guess, about renewables and the real portfolio standard and the large role that the utilities have had in procurement and kicking that ball along.

As Tiffany said, we are involved in a couple of different carbon capture and storage feasibility studies. One is the Hydrogen Energy HECA facility and the second one is our clean hydrogen power generation or CHPG. CHPG we filed with the PAC in 2007, got approval in 2008. That project has received Phase 3 funding and we also have applied for Round 3 funding. So we're working diligently there.

And with Hydrogen Energy, we are, as Tiffany said, trying to evaluate both the technological feasibility and the commercial reasonableness of that project and what future participation the utilities could have in that.

I wanted to address a couple of the specific policy questions that were listed regarding modeling at WESTCARB. As I think about production cost modeling, most of the production cost models are relatively capable of handling low carbon energy. Now, if it requires a cap-and-trade, you're going to have to forecast the cap-and-trade probably because most of the models are not indogenously going like to handle the market.

But once the emissions are ready, you can value the emissions once you've got the plan characteristics. Typically you can put those in and the production cost models will be, you know, relatively good at handling that.

In terms of real-time dispatch, and at least right now, most of the carbon capture plants tend to be must-runs. They're base-loaded plants. So it's not terribly complicated to put it in must-run. Whether you do that with a, you know, a low market clearing price or whether you're simply forced into run.

So I don't think there's, at least currently, as much integration as you might think although I think it makes a lot of sense to start looking at those issues because a little bit further down the road when renewables are perhaps

33 percent and there's a lot more intermittency in the system, there will be a higher premium on not being base-loaded because you'll need -- you know, we as a state will need the ability to ramp more -- specially you throw in ones through pooling and, you know, potentially the removal of those plants. So we'll wind up with a state that has less ability to ramp and integrate intermittents.

So you know, I do think there's a level of complexity coming here in the not too distant future and how do you remove the carbon from a variable resource like a combustion turbine for, you know, sake of description. So I do think there are some issues there, but I think, at least, some of the key ones probably can be dealt with in the -- within the existing frameworks of the models.

Tiffany hit one thing directly on the head which is full scale plants aren't going to move forward without cost recovery certainty. And to the extent that all first-of-the-kind plants tend to be above-market costs, we need to understand very clearly how to recover those above-market costs. And whether that's through, you know, government subsidies that essentially bring the plants down to market production costs or whether it's through a broad sharing of above-market costs, you know, almost preferably with all Californians, but you know, sort of at a minimum with all benefiting customers, I think that's going to be a requirement. So cost recovery is sort of a terrestrial issue for getting plants built.

On the liability side, there's been a lot said, there will be a lot more. Certainly the insurance companies are working hard on it. But while the plant operates, those risks are fairly well understood. During the close-up period, those risks are fairly well understood. By the time you get to, you know, essentially infinity, no company wants to take that risk and I would argue probably that no company can take that risk.

And until we get something dealt with long-term liability, it's even difficult for me to understand how the Phase 3 projects are going to move forward with any significant level of CO2 injection. You know, we're working very hard with Southwest Carb, which is a sister of WESTCARB, to look at, you know, what are the characterizations, what are the risks, what are the liabilities of just putting in the test CO2 into saline aquifers.

So, you know, if that's what you're looking at for tests, it's very, very challenging to me to understand how in a non-EOR application you're going to get much movement until this long-term liability issue is -- really is dealt with.

And then I had one other observation from Craig's discussion and that regards the, you know, the fact that at a state level, the property rights where the CO_2 is injected are going to vary from California to Arizona to Nevada. And, you know, we've seen this in renewables. It's been, I would argue, probably an impediment to the (indiscernible) market during the credit market and that is that you've got different rules in different states about what qualifies for what and how things work.

And to the extent that, you know, and previously someone had said, you know, you go where the carbon is if you want to remove it. To the extent that California desires to decarbonize coal in other states, we're going to need very, very clear understandings of what the ground rules are for that CO_2 that's been removed that's been put in the ground because, you know, we risk having open-ended liability, we risk having, you know, essentially a claw-back problem if it's determined that the mass balance didn't work and, you know, perhaps instead of 80 percent capture, you only had 60 percent capture.

So, you know, with the whole multi-state issue, we're really going to have to have a very clear understanding of what happens outside of the state. And I do believe it has, you know, again, some analogies to where our RPS is coming down.

So, you know, I think the issues are getting, you know, more and more framed, but, again, without having a clear view of cost recovery and liability, it's very, very difficult for us to envision moving forward in scale anyway.

MR. HART: George.

MR. PERIDAS: Thank you. My name is George Peridas and I work at the NRDC Carbon Program in San Francisco. And I'd like to thank the Commission and WESTCARB for inviting me here today.

I'll try to give you a quick overview of where we stand on CCS and how we think the situation is in California. We think that CCS is a key mitigation in technology when it comes to greenhouse gases. And as you know, there is now a unique measure that needs to be taken, CCS is one of them. This is not just because of India and China. It also very much has to do with what we do here in the U.S. and what's done in Europe.

Our brief analysis shows that in the next 25 years, what with projected investments and qualifying plants alone will, over the lifetime, emit more CO2 than humanity has admitted since the beginning of the industrial age from all used coal. This is a huge legacy which we cannot afford to put into the atmosphere. People talk about 415 EM CO2's levels these are coming down every year as scientists revisits data. And if we do let this happen, we will be on (indiscernible) when it comes to these emissions. And we are already late doing so.

I hasten to add CCS is not just about coal. It has a variety of different applications. It can be applied to ethanol plants, to refineries, cement plants. It can even be done with Biomass leading to nets, production and emissions.

This is not from an environmental, NGO's point of view being professed solution. I stress that this is only one of the solutions. There are much cleaner and cheaper methods that should and can be applied first. That would, of course, include renewable energy and efficiency. From a technical point of view, it's theoretically possible to achieve needed productions using only those technologies.

We don't think it's a wise strategy in case something goes wrong with this, something could be technical, it could be (indiscernible) and it could be political. And we haven't yet seen any substantial evidence, at least at the federal level, that the county is prepared to switch to 100 percent, you know, sustainable and renewable energy system in the times (indiscernible) climate change. So this is one of the reasons why I think that CCS needs to be a contributor, contributing technology as well.

Now, in relation to California and AB 32, for the

2020 type of release, I -- we do not believe that CCS is needed. Nonetheless, I have to challenge, like Tiffany did, the notion that CCS cannot contribute to 2020 time lines (indiscernible) 2007 either draft would send it's -- mentioned the inability of CCS to contribute to 2020 goals. We do not think this is true. We think the technology is ready to contribute to these goals. Nonetheless, we still think that the state can meet those goals without CCS.

Which brings me to why we should be considering CCS because it's not just about California complying with a lot of historical past and are very commendable lot. The task is global and California alone cannot solve global warming. Even if it completely freezes its own emission, the problem is not solved. The problem is global and we share an atmosphere. Nothing is appropriate for a leading entity like California to also be leading on another climate mitigation technology like CCS.

I am very happy whenever it comes up to quote the shining California example on energy efficiency when it comes to keeping (indiscernible) consumption constant for a number of years. And this comes up very frequently in the federal debates. And this is a shining example. (indiscernible) has done very well when it comes to climate mitigation.

Now, I have not yet seen a similar leadership role or commitment on the CCS front on behalf of the state. And this is despite California having a number of very accomplished centers of excellence. And this includes Stanford, it includes Lawrence Labs, Berkeley and Livermore in no particular order.

The main barriers, again, were outlined in an excellent AB 1925 reports. They're not technical, they're legal and they're economic. And there is no fundamental economic reasons for the using CCS in the U.S. right now with a few exceptions. And this -- because there was no price for CO2 emissions and no mandates through the use of emissions. Of course, an exception to that rule is California.

The last time we tried to address some of the legal barriers within the state was a couple years ago in the context of AB 705. And I think the debate around that Bill which calls for the development of regulations within the states to govern CCS which would have been an improvement on the status quo. And whereby EPA can issue on its -- for the practice, but will be doing so under much more incomplete, much less complete, set of regulations which I approve of that and state that state entities should draft a much more rigorous and comprehensive set of regulations.

The Bill was caught in a very basic level of debate around CCS which (indiscernible) for example, often. This is one of the implicators of the lack of knowledge around the technology. Lake Nyos was another example of volcanic emission in Africa which led to fatalities and animal kills and plant kills and so on. It has nothing to do with sequestration site. The two are fundamentally different and on opposing ends of the spectrum. Nonetheless, this is what was the focal point of the debate around the Bill and I think it was an indication of how much is known within the Legislature about the technology.

Unfortunately I think the whole Bill was also caught up very much (indiscernible), a very controversial and in my view, badly located time proposal and (indiscernible). Nonetheless, I haven't yet seen any evidence that the debate or the level of the debate on CCS has changed. According to the State, in think this is a task that we all have ahead of us if we are to take this technology to where it's needed to contribute to emission refuse.

The task for the states is no longer to lead, but when EPA was not doing anything on the regulatory front and though it would be a reasonable place to go in California because the state was already leading in many other areas like AB 32, like SB 1568 and so on.

Now, the task is very much to catch up with what EPA is doing and what a number of other states are doing on the legal and regulatory front. And we've seen some encouraging movements on the CPC front, at least lately. I do not know any of the details, I'm not expressing supporting it, but at least we can see that the debate is happening in an intelligent and productive way.

I think what we need within the states is a champion on the issue of CCS. We haven't yet seen that. We're very grateful for what WESTCARB is doing. And nonetheless, I think it's evident that the hard work made on behalf of the WESTCARB people are putting in is concerning lack of resources and lack of funds.

The funding comes, to a certain extent, from what the previous administration decided, the Bush administration decided was an appropriate sum for CCS. We contend that this is not sufficient to take the technology where it needs to be nationwide. So please carry on your good work, but I think also need help.

Finally, two things. We need to be sensitive to siting issues. Having a technology that's worthwhile is not the same as saying that it can be sited anywhere. We need to be sensitive to the locale, we need to be sensitive to local communities and also to environmental justice issues. And we have a situation, California has -- someone stated that someone being a major industrial facilities are located in disadvantaged areas. These are pollution hot spots and the local communities have been calling now for a number of years to put out (indiscernible) facilities. And I do not think that it's credible to say that there are none. In fact, if you drive by a refinery, I think you can unquestionably smell it.

And finally, a word on my ability. We do not subscribe to the (indiscernible) that's long-term liability isn't an issue. We definitely believe that it's a procedure issue and I somewhat flippantly call that utility anxiety. I think it's the canary in the coal mine that says that CSS today is not a viable business proposition except in a very few cases.

There were a number of examples that include hazard recovery, waste disposal, acid gas injection in Canada, natural gas storage where the practice is developed and flourished without a surrounding indemnity regime. I do not see how this is fundamentally different. CCS, I think, is a very definite problem that we need to get through, but it's something that we need to be very, very careful how we portray this. I don't think that taking a sledgehammer to a problem that tweezers can solve is advisable. And I think that we run a risk of painting CCS in a very bad light and I think that liability in a blanket indemnity regime is not commensurate with the inherent risks of CCS which, in most cases, will drop off after injection.

Having said that, the issue is somewhat confused because people mean different things by long-term liability. I think there is definitely a need and it's a very good idea to have a scheme in place for the long-term stewardship of care of sites. And I do think that a state or federal entity would be the appropriate body for that. Now that is very different to handing out indemnity to operators for things that they might or might not have done during the operation or life of a product.

So with that, I will thank you.

MR. HART: Thank you. At this point, I'd like to open this up to questions. Commissioner Byron, do you have any questions?

PRESIDING MEMBER BYRON: Well, that's very kind of you, Mr. Hart, but I figure you're the legal expert here. I do have one or two, though, that I'd like to ask.

MR. HART: Please.

PRESIDING MEMBER BYRON: And it goes back to in your initial presentation and I think this panel might be able to contribute in a significant way. There's a number of states, obviously, that moved forward on other legislation. What can we learn from that legislation? I don't think we've gotten much here in California at this point and clearly we're going to have to do this on somewhat of a regional basis, if not federal. So what can we learn from some of that legislation to those of you who that have evaluated or looked at what other states have done?

MR. HART: Who would like to field this question? I'll start off.

PRESIDING MEMBER BRYON: Please.

MR. HART: As I pointed out, there's been a dozen states who have taken significant legislative actions already, passed into law. There's 20 plus more that are considering actions. So, if you're looking for examples, there is a wealth of examples out there. I certainly would look at Wyoming, Montana, North Dakota. We know that Pennsylvania and Texas and other states are going to be taking action soon. There's activity in many other states. So there won't be a shortage.

But the three things that I think are significant and we can debate this as a panel, too, are those states that have set up a financial insurance mechanism for remediation. States that have taken -- set up a mechanism for transfer of liability, the long-term liability.

And just for purposes of clarification, the liability that we're talking about is not operational liability. People that work in the industry who inject CO_2, you know are or are asked to do it in an R&D context before a commercial operation of it, we don't know what -- based on the survey work, we don't think there's any issue there. So we really are talking about the long-term liability, the stewardship liabilities which were referred to.

That is the second thing a state can do that would be significant. And there's been -- the other thing that I think is very important is setting up a clear regulatory framework for dealing with potential liabilities and a clear signal to the private sector as to what they need to comply with and not comply with.

And I think our panelists will have -- I'm already a bit provocative here, I think our panelists will have views on what will be helpful to them and not helpful to them. And I think they should comment on that as well. Susann.

MS. RAU: Thank you. I mean, I did mean to say thank you very much for inviting us here and asking a variety of stakeholders. This is a really great opportunity.

We don't have a specific means that, you know, oh, you need to address long-term liability in this way. So it could be through bonds, it could be a public/private type of partnership. It just needs to be addressed. And if it's different in each state, we can deal with that.

I think the important thing is for the underlying basis to be a scientific approach. And I think George touched on that really well, that if it gets sort of taken aside by a non-scientific, just kind of fear, that was just detrimental to the technology overall and it doesn't take us forward in terms of mitigating greenhouse gases.

MR. PERIDAS: (indiscernible) is different because there was hardly anything on the regular front. A lot of things have happened in the meantime, the most significant which is the ongoing EPA rule making which will under a projected 2010 to 2011 time frame promulgate rules for injection and detaining reservoirs.

There are number of things that are missing from this rule making. First of all is what happens if sequestration occurs in hydrocarbon reservoirs or oil and gas fields. How is that regulated. And the side question to that is if I am doing enhance or recovery, can I learn how to sequestration and can I get credits. This is something that has not yet been addressed either by that rule making. It might be partly addressed by the Greenhouse Gas Registry. EPA rule maintenance underway. But my understanding is it will not be fully addressed. California could ask that question and it has a reason if the HECA Project goes ahead to ask that question right quickly.

The second thing is deciding which agencies would regulate CCS in California. Would it be left in EPA? Would it be out-of-state agencies? That's a question that the Legislature and policy makers need to decide.

And I think the third thing is the property rights issue and referring to pore space ownership where the CO2 would go. Case law usually says that this is -- ties to the -- into the surface owner and I think this is the most credible argument to make. Several states have gone ahead and actually codified that.

None of that doesn't make life any easier when it comes to massing those rights in order to do a project. I think we need to be careful how we do that in a cognitively strained well. I think landowners should realize that they are sitting on top of a resource which has value. And I think the way in which these rights are handled and valued are something the states will have to deal with, unless we're talking about federal lands, one by one. And I think they need to be making a California recipe for California which is fair and equitable.

MR. HART: The -- a note. The cost of acquiring the rights to a subsurface area that's capable of sequestering substantial amounts of CO2, we have a little bit of experience with this from the Phase 2 projects because one of them was, again, in the EOR context. The partnership that was evolved could not have accomplished that without any EOR partner and I understand it took two years of lawyer time. I don't know exactly what the deal was, but it was significant.

So that can be a very significant barrier. Two -- at least two states have passed unitization laws to help with the costs, to help reduce the costs of aggregating the amount of land that's needed.

MR. NELSON: I think at least right now, the states are holding off, especially on the long-term liability issue, in search of a federal solution, realizing that if states step out in front, then the feds will have even less impetus to do that.

So, you know, to the extent that we're at a standoff, I don't see that standoff necessarily breaking either. You know, I do agree, it's a stewardship issue. It's not a -- this is not a get out of jail free card. I mean, there needs -- the moral hazard issues need to be dealt with. You can't give industry or anyone else a long-term solution that stops them from acting in an ethical and reasonable fashion along the way.

But again, I believe that for both operation and for close-up, I think we can find reasonable solutions, you know, whether it's an insurance basis or even a self-insurance.

But this longer term, and I, you know, recognizing that I think even a stewardship solution is sufficient. I don't think that anyone, again, needs a, sort of a long-term, non-funded, just take the liability away. But there needs to be a way to understand that long-term liability because the open tail is very, very difficult for a, you know, for a corporation to deal with.

MR. HART: David.

MR. ALBRIGHT: I think just to amplify a couple points. On the mechanics of geosequestration, basically within a year to a year and a half, we're expecting to have final rules on the books governing the mechanics of geosequestration.

So certainly EPA does not want to impede any state from moving forward as the state sees fit, but I think it does make sense to focus on, you know, the CCS is a long process. The actual mechanics of putting the CO2 into the ground is only a portion of that process. So I think it would make sense to focus on the owner aspects of the process and how that would be governed in the State of California.

The final rule that comes out in the next year or 18 months approximately, I think it's important for states to think about, as I think George mentioned, how the state, if they want to take delegation of plastics, wells, oversight of geosequestration, how that would work in the state. Basically, a state would have to demonstrate -- a state would either have to adopt the EPA's rules for the mechanics of how CO2 is sequestered or write their own rules, but EPA would then need to determine if those rules were at least as stringent as the federal rules.

So obviously there's some risk, I guess you could say, if a state moves out and adopts legislation or regulations governing the mechanics of sequestration prior to EPA finalizing those rules, if they want to take the program because they would have to be sure that those requirements were at least as stringent as what ultimately was promulgated by EPA.

MR. STETTNER: Let me address this as well. If we can use the Class 2 as an anolog when we receive (indiscernible) 1983 for Class 2 and accepting the federal requirements that was the Division of Oil and Gas requirements that were stringent. And I expect we may see the same thing if we accept primacy for Class 6, we'll probably see the more stringent, regulatory framework for Class 6 from the state side.

I also want to mention that the states are coordinating their efforts with the Interstate Oil and Gas Compact Commission and the Ground Owner Protection counsel.

On the Bio-GCC effort, the Division was involved with the development of guidelines for -- the states can use for implementation or promulgation of rules in their state. And I believe North Dakota used those guidelines. And those guidelines were reviewed by the entire Bio-GCC membership.

And then Groundwater Protection council, they're moving forward now with coordination effort and very similar to what the GCC has done. So there is a very good coordinating effort between all the states. We're not reinventing the wheel, we're learning from each other.

MR. HART: I'd like to add to it. We'll set about this issue between the standoff between the state and the federal government on who's going to deal with liability.

Just to remind you that in the future GEN projects, Illinois and Texas both needed to move ahead and take up liability on -- at the state level in order, possibly, to be competitive for those projects, but they did that. The federal government was not going to do that.

And I -- also one of the points that I think that George made is that, summarizing, that a blank check should not be offered here and I happen to be in agreement with that. I don't think it's necessary. If you look at -- there's a number of ways to limit or restrict the kinds of liability protections that are offered. If the state does take liability on this, a number of states have, they do it after a period, usually ten years.

They subject those projects to a number of requirements. In the Bingaman, you can look at the Bingaman Bill for examples of this. Very strict guidelines as to what they must comply with, both during operation and then the certification requirement that they've been properly closed. They need to be certified, I think, by the DOE, secretary of the DOE that they've been properly closed or another organization that they would accept.

And then there's a number of ways to limit any kind of a liability provision by depth of injection, volume of injection, pressure tests. There's some fairly sophisticated modeling being done at WESTCARB, it's very interesting, through Lawrence Berkeley Lab on risk assessment. So there's ways to get at this issue as to what should and shouldn't be underwritten.

The last thing I'll add to this is there's obviously the possibility of the private sector stepping in with some form of insurance. And there is a company that has offered an insurance policy, but it doesn't take up the long-term liability.

So whether it is the federal government or the states or the private sector or a project party, the only two that we've seen move, I think, on long-term liability is the EOR community and the Phase 1 and those are very small scale projects, which Mike Stettner pointed out. At larger scale, they may not work, they may not work the same way. And the other is states. And there's several examples of states that have taken on liability.

MS. RAU: Can I just interject that I'm hoping that the rest of the conversation that we have, we could actually shift away from the discussion around liability? And I've been echoing George's concern because we just keep hammering on it over and over and over again. And I see it's an impediment.

I think we need to talk about enabling the deployment of CCS. One of those might be, you know, policies that encourage and incentivize, for example, entities to actually do that. Maybe we could shift a little bit in the conversation.

MR. HART: Sure. This -- the discussion followed from Commissioner Byron's question. Commissioner Byron, have we addressed the question?

PRESIDING MEMBER BYRON: Well, Ms. Rau, before we leave the liability question, because I know you did say earlier you don't see any regulatory or liability authority that's needed except for long-term liability as I recall.

But I think there's a difference of opinion amongst panelists. And I was just curious to get this. So I just want to drill down on it just a little bit more, if I may, because I think Mr. Nelson indicated that there are many issues that need to be settled before we probably can move forward on the Phase 3 projects as well as some of the other projects, and I'll equate that with the early movers that you have discussed.

So I'm just curious what the other panelists think. Will we need to settle the long-term liability issue prior to moving forward on Phase 3 and other early mover projects?

MR. BIRKINSHAW: And just a kind of corollary, could maybe one of the regulators here speak to how this is handled, that is long-term liability, in the EOR contexts. My u place here in California. To what degree does that become a viable framework for moving to CCS?

MS. RAU: You're asking me or one of the others?

MR. BIRKINSHAW: Well, just whoever -- well, whoever wants to speak to it.

MR. STETTNER: I think one thing we need to keep in mind when we're talking about EOR versus saline is that we have a lot of data on oil and gas fields. You know, the fluid has been in there, gases have been in those zones for millions of years. What we don't have is a lot of data on saline reservoirs. So that may be an issue or that will be an issue.

When you're comparing the liability or the long-term stewardship of a saline reservoir versus a EOR reservoir, they may not be on the same field and plane because of the history that we have in oil and gas reservoirs. We know how they're going to behave.

Specifically, an operator is released from their liability for an oil and gas well, including injection wells after abandonment for -- you know, once abandonment, the well's been abandoned for 15 years and there isn't any issues associated with that, the operator is released from that liability. We don't have anything but the facilities themselves and that's something that we have to address.

MR. BIRKINSHAW: Has that worked out well, so, the history with that?

MR. STETTNER: Yeah, it works out fine, yeah. We haven't seen any problems.

MR. NELSON: And I do think I want to try to untangle that part of the liability because, you know, specifically, our CHPG project is working with Southwest CARB and that would be injections into saline aquifers where we don't -- we just don't have a clear picture whatsoever of the long-term liability there. As I said, I think we can deal with the intermediate term through financial vehicles, but long-term, you know, very problematic.

EOR is different. It -- you know, I think I simply echo the statement that it's geologically better understood. And to some extent, there are, you know, existing rules and those rules may be sufficient.

So I have, you know, I have a much different level of concern for EOR because it's on a path already. But for saline aquifers, which are, you know, really, you know, at the beginning edge of their knowledge, you know, I do have long-term -- long-term liability concerns me before I probably could even move in to test it.

MR. HART: I would like to make a remark that in the Phase 2 study, one of the things we found is that research partnerships who needed to accomplish the goal of getting their projects done often times looked to the EOR because it was easier to do. And they had a tremendous amount of support there. So, and it goes to the point that EOR is really very different than saline.

And the other thing we saw is that for the utilities, it wasn't just something, California Edison was not one of the utilities in that study, there were other utilities that had really significant concerns about liability and were not able to move forward as a result.

MR. PERIDAS: If I can quickly, I'll start this. I mean, what Mike was referring to is that in EOR, there is a financial instrument which gets released after the wells have been properly plugged and abandoned. But that's not the same as an operator being -- handing off the liability or being indemnified against lawsuits for intentional misconduct, negligence, et cetera, et cetera, et cetera. And I think this is something that EOR operators, unless somebody tells me otherwise, have lived pretty comfortable with for a number of decades now.

And what's different between now and EOR is the fact that we haven't got that level of comfort built. Now, I wasn't present when the EOR operators were building that comfort, so I suspect that the financial -- or the economic drive was sufficient to make them shoulder that risk and to say, okay, we'll figure it out. Now, there's a lot of water under the bridge, they are comfortable with assuming those risks, they are comfortable with management.

The way I see CCS is that probably the risks are similar, but we haven't yet gotten to the stage where we build that level of comfort. But I mean, saying we need to be very careful as to how we resolve that.

MR. HART: Anybody else have any comments?

MR. STETTNER: I just wanted to define the points, what George has referred to as our bonding requirements. Technically our bonding requirements are for the drilling of the well and that's not for the long-term operation, although the operators do maintain a blanket bond, they just carry through with their operations. Technically that bond could be released if after six months of consecutive production or injection.

MR. HART: But also it would be worthwhile pointing out that bonding or financial insurance mechanisms in the EOR context are common in all oil producing states and there's a number of models he can look to in trying to develop something for CCS. There's a lot of analogs available.

MR. STETTNER: And I just wanted to underscore that that is for the well and not for facilities.

MR. HART: Other questions. I'd like to make sure that we take care of questions from the Commission first, but certainly welcome questions from the floor as well.

PRESIDING MEMBER BYRON: If I may, then I'll ask one last question. Mr. Peridas, you've mentioned concerns about environmental justice issues and I'm having trouble with making that connection with carbon capture and sequestration. So could you help me understand that?

MR. PERIDAS: I think the siting of any industrial facility also carries environmental gases implications if it's located in certain communities. And there's things (indiscernible) as being supportive of ecology that the technology is a good idea and a needed one and climate portfolio is different than saying with this site of operation can or should be located ever and I was urging an inclusive and rigorous treatment of local community issues when it comes to deciding not just CCS project but any project.

MR. HART: Thank you. Questions from the floor. Rich.

MR. MYHRE: Hi, I'm Rich Myhre with the council for BKI. Got a question for David Albright. It was widely reported in the press recently that EPA made a determination that it could, in fact, regulate CO2 under the Clean Air Act. And then of the two types of steps it could have taken in that determination, it took the less aggressive of the two in hopes that Congress would actually pass climate legislation. And in either case, whether Congress does, even if it does, presumably EPA will be a main implementing entity. And if it doesn't, then the Agency may move forward under the Clean Air Act.

Do you envision any rule making on the air side effecting the timetable for completion of the final Class 6 rules?

MR. ALBRIGHT: Certainly EPA is looking to Congress to see what actions will be taken there. As far as I know, they're not making impact on this Safe Drinking Water Act role that I had discussed that the proposed rule that we put out for geosequestration by the air regulations. I think there's a demonstrated need to have a regulatory framework in place and the EPA is moving forward to put that framework in place for injections now, too.

MR. HART: Thank you. Other questions?

MR. PERIDAS: Rich, if I could also answer that quick because we had cemented comments to that effect to the EPA. The current rule making totally cites Safe Drinking Water Act authority. And it does cite Clean Air Act or any other authority that would be in place for the purpose of preventing the emissions of CO2 to the atmosphere, which is not the same as the (indiscernible) which, you know, it's a logistical mechanism through which allowances will be accountable reconciled.

We think this is a problem and we think that it's a vulnerable point of the current rule because any climate bill is likely going to link to an appropriately regulated EPA class. And the purpose of the climate bill is to prevent and account for emissions to the atmosphere. The folks of the U.S. (indiscernible) is simply not to determinate on ground source (indiscernible) water.

From a physical point of view, the steps needed might be very similar. From a legal point of view, the two are very, very different. And we think this can be fixed within the 2010/2011 time line and lead to the engagement of a stronger rule that will also avoid this pitfall.

MR. HART: Thank you. And any other comments on this question from the panel? And any other questions from the floor or from the Commissioner.

PRESIDING MEMBER BYRON: Well, I think we should go back to Ms. Rau's issue. I won't say issue. You were trying to take us off liability and move us toward incentives and I pulled us back. So let's make sure we give the panel opportunity to discuss incentives.

MR. HART: Sure. I think what I'd like to do is ask the whole panel what they would like to see, what they would recommend to the State if they were given an opportunity to make a recommendation to the State of things they'd like to see done and things that they -- as priorities.

And, so, I'll start in the opposite order. George, if you would like to start us off. So two or three items that you would recommend as priorities to the State for action here to support the adoption of CCS, given the current state of play.

MR. PERIDAS: I'll broaden it just a little bit, I would say, and that's Waxman/Markey. There are lengthy provisions in that federal bill that deal with what we think and what other U.S. climate action (indiscernible) members agree and that is the primary barriers for CCS and that's the economic piece.

The first few plans, again, cost more than the next 10 or 20 and we need to get over that hump. There are provisions that would use a fraction of the revenue from cap-and-trade to give out incentives on the job at the time, sequestered basis for a number of gigawatts. Overseas has deployments on the power tech side and 15 percent of that is set aside for the industrial side.

MR. HART: George, I'm going to ask everyone to focus on what the State of California could do as opposed to, you know, what's beyond their ability to influence.

MR. PERIDAS: I think the State itself faces a more limited budget. We've seen had controversial passing that budget can be. And there are competing uses for State funds. I think the State could consider how we can support CCS, it should do so, bearing in mind that there are technologies that are cheaper and from an environmental point of view preferably.

MR. HART: Mark.

MR. NELSON: Well, I think, you know, cost recovery continues to be the number one issue, I think, for investor-owned utilities. Obviously, when you're above-market costs, federal participation is the best. State, sort of state-wide participation would be next and at a minimum, assuring that, at least, all benefiting customers, you know, participate.

I also think that having some fairly clear rules for what out-of-state resources would need to look like, will help us because, you know, the coal does not intend to be in California. So whether it's post-combustion capture on existing plants or whether it's some sort of pre-combustion capture on new plants, we really do need to have a clear understanding of what low carbon means and what we would have to do out of state to achieve that and how that would fit into the portfolios of the utilities. It's not, you know, it doesn't fit into RPS. It fits broadly under AB 32, but -- and again, I think we'll probably need a little bit more understanding of that because I'd hate it to get tangled up in a problem where the out-of-state rules were different in a different state and somehow we couldn't get credit because I think it would make it very, very challenging to even start a plan like that or get cost recovery. So we need clear rules, I think that would be our support.

PRESIDING MEMBER BYRON: So if I may, does that have to do with the cost of carbon? Or are you looking for loaning guarantees or tax credits or something else, other vehicles like that?

MR. NELSON: I think -- you know, part of this, I think, goes back to the EOR discussion which is EOR has a long history where they have probably, and again, I wasn't a part of that either, but they probably bumped into a number of issues along the way, resolved them, put that into practice and moved ahead.

And as we get into other states, again, it's not completely clear to me that if a plant were in a different state and that state somehow certified carbon capture as being a particular method, that if we got an alternate view of that in California. So maybe it's 80 percent captured in Arizona speak, but it's only 60 percent capture in California speak. And to me, that could become a significant problem that even has a risk of a fall-back where you thought you were in one position and later you find yourself in a different position.

So, again, I think just the clearer we can be with this. And it may be that it's just simply going to take time, that we can't (indiscernible) put that in place and that we're going to have to move ahead and find these sorts of issues. But you know, removing that certainty is clearly the number one role, I think, that the State can play.

MR. HART: Thank you, Tiffany.

MS. RAU: If I had two, the first would be regarding permitting the HECA facility in that it is an early mover project that has a lot of attention, a lot of people are watching to see how that goes. It will -- the permit application will include a joint proposal between us the CO2 -- or the, excuse me, the EOR operator for how the agencies work together in permitting and CEQA authority. And just kind of give you a heads up on that, that just the permitting process around the facility itself kind of soup to nuts is obviously key, I think. And I think a lot of people are kind of waiting to see what happens with the project for they're willing to actually step up and do some investment.

The other is ideally, from a power procurement standpoint, ideally you would have a low carbon portfolio standard here rather than a renewable portfolio standard. I know that's not politically correct to say, but at some point there -- I would think there needs to be some kind of role and appreciation for ultra-low carbon, base-load power to be within the mix of California's generation to back up -- you know, to firm up the increase in renewables. I think it would be helpful to the utilities to get some credit for that.

But if that -- that kind of policy framework that either the PUC or the CEC can start embracing and looking at, I think it would be very helpful.

MR. HART: Thank you. Susann.

MS. NORDRUM: Thank you. I think we touched on it a little bit, the clarification and the pore space, surface rights and mineral rights is going to be crucial. We can't go forward if you don't know who the space belongs to.

I think it also (indiscernible) treatment within the western climate region and as much as possible, federally in the U.S. so you don't have this big tangled web of, you know, especially if you were crossing state lines with the subsurface formation. That could be really, really tricky. So consistency would be very, very helpful.

And just to emphasize again, that the oil and gas industry and working with the Department of Oil and Gas, you know, has so much history and so much knowledge in these areas, especially things like site assessment, monitoring and decommissioning. And I think when you get into the very fine details around things like monitoring and verification, there are technologies that can, you know, achieve the goals and there are technologies that can be, just, you know, hugely extend across the project without really furthering the verification effort.

Like I said, it would be very important to work the details with people that have been there.

MR. HART: Thank you. David.

MR. ALBRIGHT: Okay, I would say, from my perspective, to continue to participate in the regulatory process that EPA is going through on the Safe Drinking Water Act regulation at least. And would include commenting on the upcoming notice of data availability just to ensure that whatever EPA's final rule is definitely considers any specific or unique issues to California.

Secondly, I would say to prepare to implement the Class 6 program if that is something that the State is intending or desiring to do. And that would include determining who would take primacy within the state, whether that would be a division of Oil and Gas, for example. And just otherwise focusing on elements of the process that are not being addressed by EPA's proposed rule.

MR. STETTNER: Okay, I'm going to comment on myself, on our agency. One thing I'd like to see us do is to develop statutory authority to be able to do CCS or to be able to do at least the storage part.

Our authority right now is specific to oil and gas, expiration and production operations. For us to start implementing or to implement or ponticate [sic]regulations for gas storage, CO2 storage, we need to have that statutory authority first. That's where we would like to go. And we are willing to accept that responsibility. And we would be looking at, you know, a primacy application very much similar to what we did for the Class 2. That's what we envision.

MR. HART: I'm going to give some input on this question as well. Clearly defining the pore space ownership and the ownership of CO2 does help clarify -- if you clarify the rules of the game, then it enables the prime sector to go out and deal with those, with the rights that it needs to acquire and to go in and allocate risks among them.

The other point that George raised and it's been commented on, is the siting issue. I think that a sophisticated outreach program is going to be really important for the State. In the DOE partnerships in Phase 2 and in Phase 3, a tremendous amount of attention has been paid to outreach and education. Without public support and understanding, this will be difficult and more costly to do. And that process can go well or it can’t. The experience in the DOE partnerships is that in general it's gone very well. There's been -- but that's been a function of how much attention has been paid to it. So I think that that's a very important point.

And then finally, I think if the State really wants to see this take off, there's several ways to do it. Certainly if the State sets a cap or a community control mechanism, that is going to be balanced against any potential liability, maybe in an unquantified way or even perhaps a quantifiable way. I don't think that's what industry is coming here asking for, but that -- is obviously we're having this discussion in the absence of the strict cap, the liability assessment changes once you've got that. But if you do have a transfer of liability mechanism, as a number of states have done or are considering, then clearly this -- you are better positioned to see this technology being taken up on an early adoption basis.

Other comments? Other questions?

MR. PERIDAS: Just a quick note. I think I understood your question, so we don't (indiscernible), so that we just (indiscernible) about education and public recession on CCS, we hosted to watch (indiscernible) which Larry also presented which had (indiscernible) and goes to the Commission. One was in Sacramento, the other one was in Los Angeles and they were four-day workshops to talk about climate mitigation, general, then specific, specifics of CCS, how it's done, et cetera, et cetera.

I think this is only one example of what needs to be done, but I think all these policies that were mentioned and measures that were mentioned by the panel, if they stand a good chance of being active, will require, I think, sufficient knowledge of the (indiscernible) of CCS by the Legislature, and which I don't yet see that it's there. And not just the Legislature, but also the variety of stakeholders involved in it and such and such.

MR. HART: Thank you.

PRESIDING MEMBER BYRON: Well, except for perhaps some legislators who are given this legislation requirements to evaluate this subject. No, this is all very good discussion, it's all good discussion. I just have a couple of remarks I'd like to say before you break, but I don't want to precede anything else you might want to do.

MR. HART: No, please.

PRESIDING MEMBER BYRON: I am unfortunately not going to be able to rejoin you after lunch and I suppose -- the reason for it is because I've got a conference, scheduling conference with regard to another complicated siting case that we have going on in the State and I suppose I would direct my comments with that regard, in that regard, too.

Those early movers, these are going to be complicated projects. They're going to take on new issues that we really haven't dealt with before in the State and when you're also bringing in new agencies either at the state and/or federal level, it's going to complicate the issue even more. But I'm very sensitive to that and also to the importance of carbon capture and sequestration. We've got some great expertise as demonstrated on this panel this morning and I'd like to really thank all those that were here today, particularly those who gave up some of their Sunday to be here as well.

I'm very interested in your written comments and particularly your recommendations for California moving forward with carbon capture and sequestration, that would be extremely helpful to the IEPR Committee, with regard to ensuring the public of the long-term safety issues that we need to address here.

So, again, thank you for this excellent discussion. I'm not going to close out the session. I think that responsibility falls elsewhere.

MR. HART: Thank you, Commissioner. And I guess without further questions from the audience, I'd like to, once again, thank the Committee. This was a very good discussion of the issues facing us on the policy side for the CCS. And I think what we now do is we have a break for lunch and we will reconvene here at 1:00 if I have that -- 1:15, 1:15. And lunch is on your own. So thank you very much.

(Lunch recess)

MR. MYER: I guess we'll pick up where we left off. And so, this afternoon, we have some more focus discussion about several issues, specifically related to the -- to both, to the legal and regulatory aspects, but beginning with a bit of a update on the capture side of the issues, technological issues.

And before we -- before I introduce Dale, I did want to also mention for those that are linked in through WebEx to please, if you have questions related to particular talks, put them up on the chat line and we'll catch them when we're done with the presentation.

So with that, I want to introduce Dale Simbeck from SFA Pacific who's going to talk to advances in CO2 capture technologies.

MR. SIMBECK: Thank you, Larry. You want me to complete at what time?

MR. MYER: Half hour, half hour.

MR. SIMBECK: Okay. So ten till two. We'll run five minutes late.

MR. MEYER: That's not a problem.

MR. SIMBECK: Okay. What I'm going to do, you -- everyone here has the slides and hopefully the ones on the WebEx can gain access to those slides as well. They're -- I can't get this to go. Okay. What I'm going to do is they're very busy slides. They're really talking points of a lot of detail I won't have time to discuss. But if I do a good job in the presentation, you'll be encouraged to go back and look at some more of the detail.

I'm going to quickly talk about some background on the CO2 issue, sources and options to reduce it and then, doing that, to focus on why I think CO2 capture and storage is important for these ambitious goals, the CO2 reduction that California has for the long term. And then talk technology-wise about these three options on capture: post-combustion -- or pre-combustion, then post-combustion, then oxy combustion. And then talk about some of the advances and finally some costs and address applications relative to California which tends to be a little unique compared to other things you hear in capture and storage.

Very briefly, been working this for about 20 years. This last year I spent a lot of time on a big study for the Business Roundtable that's becoming public anytime now and also some work on -- for MIT on capture which was actually funded by a major U.S. utility.

In general terms, we only have four ways to reduce man-made CO2 emissions. The first two you don't talk about much and that's reducing world population, reducing standard of living. But the fact is, this is a recession year worldwide. So this year, CO_2 worldwide will go down with the recession.

What you have to focus on is reducing energy intensity and carbon intensity and the particular applications that apply to the big elephants in the room which are the United States and China. The United States is 20 percent of worldwide CO_2, but people tend to lose sight they're also 20 percent of the worldwide gross domestic product.

China has passed us by, but now they're in a recession. Their electric demands are actually going down instead of going up at this point.

Here is the overall CO_2 emissions for the U.S., broken out by application fuel. And I did this to point out an important point and that is that there is -- the two big dogs that control CO_2 emissions in this country is oil for transportation and coal for power generation. And that's about the same for the world. So each of those are about 40 percent on a world basis as well as an overall U.S. basis. So you really have to focus on those two, the coal for power generation and the liquid fuels for transportation.

Now, California is very uniquely different. And that is transportation is by far the biggest CO_2 emitter here. Even when you include the imported coal-based electricity, electricity is still relatively small here due to our electric use being small and also the large amount of natural gas use makes that CO2 from electricity relatively small here. So we're unique compared to the rest of the United States and the rest of the world.

And that brings me to an overall important slide and that is to develop a carbon-constrained world, we need all the options. And I don't have time to talk about the other four, but they're very important: conservation, efficiency. Natural gas use will likely go up at the expense coal. In a carbon-constrained world, nuclear has to make a comeback. Renewables get very important.

But you also need capture and storage for two reasons. One is the large potential that CO2 has on that reduction with those fossil fuel uses now, but also if we move into a tipping point and have expanded global climate change, these fossil fuel based plants, especially the coal plants with solid feed, they could blend in waste biomass for these double reductions. I was glad that was mentioned this morning. That's very important for the long term.

A key part of our private client work on this issue is the power generators will be forced to meet a disproportionate share of the reduction. You can't really put a lot of this on to the residentials with their transportation. There isn't an effective way to do that on cars unless you change the biomass fuels which tend to be a little expensive. Other is you can't put it on industrials because they have to compete in international business. And so you can literally force the industrials to move to China. And the net effect is, you just increase emissions whereas the power plants can't move to China and they're the big users of coal as well. So they're the ideal ones to look at in terms of these reductions, but will have those fair shares across all of the sectors that consume electricity will help pay for that.

Mitigation options in California, as I mentioned before, tend to be unique and that is you have a lot more transportation fuels and natural gas to electricity whereas most of the world, you see this a lot, of coal to electricity. And that's going to tend to make costs of CO2 mitigation more here in California than other parts of the world because we don't have that large coal use.

But even without that coal use, I think we still need CO2 capture and storage to meet these ambitious goals. We're going to want to look at this to develop in long term, perhaps to use the biomass, as I have mentioned before, to get that infrastructure in place. And I think the key challenge we have is public acceptance of this as an option. But I think we need it if we plan to meet these ambitious goals.

A very quick overview on capture and storage, there's three key parts. You need a location where you can store large amounts of CO_2 in geologic formations and we have those in California; large point sources for economies of scale, we have some of those; and then you have to get to a high concentration, compress it to supercritical conditions to store it as well. So those are the three main parts.

And as Elizabeth mentioned this morning, the U.S. has been a world leader in CO_2 capture and storage, but we don't think of it that way. It's -- normally, CO_2 for enhanced oil recovery and we have these pipeline systems on the slide. And I think more importantly in this slide are those squares. Those squares are anthropogenic, man-made CO_2's that are captured and used as opposed to natural CO_2's. So roughly, of this 40 million tons a year of CO_2 that we store, about 20 percent of that comes from man-made CO_2 and we're getting these benefits of this enhanced oil recovery as well.

Now, I'm going to walk through the four -- the three different capture systems. And from this last slide, hopefully you can see that we have these two large systems and actually both are pre-combustion. And so, pre-combustion is being done commercially in a very large scale, but not in power plants. That's the issue that's missing.

So, you can look around the world and in pre-combustion, you generally look at gas location of any carbonaceous fuel into this mixture of hydrogen carbon monoxide and converting that into a mixture of hydrogen CO. and those are done at very high pressures and so the separation of that CO2 is very easy. And that's why the pre-combustions tend to have the lowest loss in capacity and efficiency because all this is done at high pressure.

The status, as I mentioned before, there's large plants throughout the world, a lot of ammonia plants, a lot of hydrogen plants, the one big S&G plant in the U.S. So if you look around the world, there's about 40 gigawatts thermal operating plants with CO2 capture. These are large numbers. In fact, the only gas location plants that don't have capture are the few IGCC plants and power generation. All the others do.

There's also experience with hydrogen enriched gas in turbines, but those are not the state-of-the-art turbines. Those are in cogeneration and refineries, not these high firing temperature turbines for a central power plant.

The attributes of a pre-combustion, I think the greatest is you're using hydrogen as an intermediate. And that opens up a lot of other potentials in the cogeneration with gas turbines, but also these low carbon fuels, making liquid fuels or synthetic natural gas or even hydrogen for fuel cell cars. So you can't do that with steam after combustion.

Post-combustion is slightly less developed at this point. It tends to be harder to do in flue gas because of the presence of oxygen, very low pressure, very low CO_2, what's referred to as partial pressure, taking the total system pressure times the percentage of CO_2. It's very low. And so that operation tends to require a lot of circulation, a lot of stripping steam. And that's where you get the large power and capacity losses.

Now, the status of this on flue gas, not to be confused with natural gas, but on flue gas, the largest commercial plant operating in the world is only 330 tons per day. So it's on order -- magnitude smaller.

Now there are some important attributes for the post-combustion. I think there's two. The traditional electric utilities are more comfortable with these flue gas approaches. They have a lot of flue gas desulphurisation and selective catalytic reduction as well. So they're use to these flue gas approaches.

Also, you can retrofit to existing systems very easily with these provided you're honest to yourself about the tremendous energy and power needs that they are going to take. They're going to reduce the net capacity and net efficiency.

Oxy combustion tends to be the least developed at this point. As the name implies, you just replace the air with oxygen. That's the easy part. You're going to have to circulate a lot of gas or water injection to get those temperatures down to something you can control. It's also important that to realize that oxy combustion requires over twice as much oxygen as pre-combustion does and that's its Achilles' heel in terms of its cost and inefficiencies are related to that tremendous amount of oxygen combustion.

Now, you don't have any even large size oxy combustion plants yet, some small ones I'll talk about in later slides, but they're coming along very quickly at this point. There is one commercial kiln on oxygen combustion for nickel ore. So that's being done in Canada commercially in a kiln.

Attributes of oxy combustion is that you can -- you avoid these complexities of pre-combustion which is more a very complex chemical process. You can potentially avoid the stack, have 100 percent recovery which would be a nice thing for permitting, not to have stack or any emissions at all. Potentially you can retrofit these as well, and nice retrofits are when they increase capacity. And there's two places where oxy combustion can retrofit to increase capacity; fluid cap crackers and loyal industry which I don't have time to explain the details of those, and also cement kilns.

Advance systems, and I'm going to spend a little more time on this, it's important. All three of these are pre-post and oxy desperately need large scale demonstrations. But there's other advance systems being developed now beyond the traditionals. I'm going to talk about those a little bit. For pre-combustion, we're seeing increased interest on S&G with coal with CO2 capture, like the Great Plains plant I showed before.

There's two attributes of that approach. One is you can disconnect the CO2 storage from the end use of the synthetic natural gas which is a low-carbon carrier. The other is in a carbon-constrained world, most people think that there'll be a big demand on natural gas replacing coal and the supplies and prices of natural gas will be tenuous. So this creates a back stock to control the natural gas supplies, to put these in place as well.

In post-combustion, a major -- a breakthrough was the new solvent with chilled ammonia and Alstom is aggressively promoting this. And the attributes are substantially less energy and power consumption that they can -- you need much less stripping steam and they can strip this CO2 out of the ammonia at pressurized conditions to greatly reduce the CO2 compression cost. So this is being really fast-tracked and pilot and demo plants, pilot plants running now, a demo plant is under construction that they hope to start up later this year. So that's really moving along quickly because of the attributes of the power and steam reductions.

Oxy combustion, the thing that is most exciting here that's moving along is in California with the clean energy systems where they have an innovative combination, what use to be a steam turbine, you convert more into a combustion turbine with hydrogen and oxygen and steam. And I'll talk about that in a later slide. But we need both of these and that is learning by doing with the more commercial and these advance systems for R&D. You can't do one or the other, you need both to reduce these costs for the long term.

I'm going to try to talk about costs of CO2 capture now, which is the Achilles' heel. And it's always difficult to talk about these and so I'm going to have about three slides as background before I give any costs.

The first is where the costs lie and generally speaking, about 15 percent of those costs are to get to the pure CO_2 stream, about 25 percent of the costs to compress up to the supercritical conditions and about 25 percent of the costs with a pipeline injection, geologic storage and monitoring. So it's important to think about it in those percentages because if you do CO_2 for enhanced oil recovery, that last 25 percent, instead of being a cost, can be a slight positive revenue stream, so you can literally go from a negative 25 to a plus 25 and potentially eliminate maybe half of the costs in enhanced oil recovery. So that's an important early mover.

Another issue with CO_2 capture and storage is most of those costs are associated with additional capital and internal energy use. In gross terms, for a new plant with fossil fuels, considering without capture and then with capture, you're looking at capacity and efficiency drop to somewhere between 15 and 30 percent.

Now, you can potentially avoid those big efficiency drops if you go into retrofits where you basically rebuild the retrofit to a state-of-the-art, more efficient plant. And even with the capture, you end up with about the same efficiency as the old plant, but now a zero admissions. But those retrofits are much more expensive than just the -- or the rebuilds are much more expensive than just the retrofit. So you have to watch in your costs, but you can avoid the efficiency capacity loss by doing that.

Also, the best thing to do when you look at CO_2 capture and storage is think about the increase in product costs. And I'm going to use electricity here. I don't really like to use a CO_2 avoidance cost because they depend on the baseline. And that's very tricky. But you do have to think about the CO_2 avoidance cost because what that really means is that's the minimum carbon tax that would be required to economically consider capture and storage. So that's why people calculate that, because of its importance.

And the last line on this slide is the formula. It's a very simple formula. It's the difference in the cost of the product, in this case electricity, with the capture and without. And then it's the amount of CO_2 per unit of energy to the atmosphere, originally versus what you have to capture.

And I point that out because of this next slide and that is there's three components to the CO_2 avoidance cost. It's the capital charges, the amount of CO_2 you've recovered and the fuel price in the efficiency, especially efficiency loss. And so, what that says, and Elizabeth said the same thing this morning, and that was coal or, in California, coke, the capital charge will be very high, but the amount of CO_2 you avoid and the fuel cost are both -- well, the amount of CO_2 you avoid is very large and the fuel cost is low. Whereas with natural gas, the capital cost won't be as big on that investment for capture, but the amount of CO_2 you avoid is half as much and the energy price is much more. And, so you tend to get in the situation that if natural gas prices are high, the CO_2 capture cost with natural gas tend to be higher than with coal or coke. And that's an important economic issue to be concerned with.

Another thing I mentioned before is we have this EOR potential in California and that's the place to start because of the by-product credit. We also have co-gen potentials here with heavy oil/steam simulation. That's a very nice co-generation host. It keeps your efficiency high, it also reduces the water consumption as well.

A caveat in that is trying to estimate costs right now is dangerous to your health because costs went so high the last three years and now, they're starting to drop. And also here in California they tend to be higher costs than the rest of the country. Compared to the U.S. Gulf Coast, about 25 percent higher construction costs here.

So the costs I'm going to give will be just generic costs. The U.S. Gulf Coast, $2,006. I caution you because

California costs will be higher than that. And so the first thing on costs I like to ask myself is what's the minimum CO_2 tax I would need for a power plant operator to consider CO_2 capture and storage. And that would be what's -- when the price of electricity is the same, for him to have capture or him to just vent the CO_2 and pay the tax. And so, for this generic, a new coal plant about $15 per metric ton of CO_2 and that's about 11 cent electricity. I've increased my electric cost from about 7 cent electricity to 11 cents and that's for a base-load plant that runs all the time. That would be industrial power rates, U.S. Gulf Coast, a few years old dollars. For California, our industrial rates are 10 cents now. So for California, you'd be looking at probably going to perhaps 14 to 15 cent electricity for a base-load industrial rates. Roughly about a 25 to 30 percent increase in electric price.

For existing plants, you need an even higher carbon tax because those plants will pay it off. And you need about a $75 per metric ton carbon tax to make an existing coal plant consider doing anything. It's cheaper for them to pay the tax.

The other thing you have to ask is at that $50 per metric ton CO_2 tax where I got the new coal plants to consider capture, what natural gas price could they pay and avoid capture? And because your first choice would be to avoid that big investment in capture plus all that financial risk and liability and just look at natural gas. Well, I can afford to pay as high as the 11 to 12 dollar per million BTU natural gas with that carbon tax to get the same price of electricity. And that's much less investment and much less risk.

And so that's why, in a carbon-constrained world, you'll tend to first see natural gas being used to replace coal before capture and storage and that will stress the natural gas markets with the high price. But more importantly, for California, it will make capture with natural gas tend to be a little expensive once natural gas prices go up.

In California, though, we do have these opportunities in the industrial sectors and in the power sectors. In the refineries, we have large fluid cap crackers. And so oxy combustion for those is something to watch. We have this large amount of petroleum coke and so there -- that's an ideal to use that for a cheaper feed stock. And the CO2 you avoid in that capture and storage as well and the natural gas you avoid using. And then long term, these solid fuels like petroleum coke, never forget the biomass that you could retrofit in.

The EOR's and the co-gen for the stimulated heavy steam, those are ways to get your costs down and your efficiencies up.

Other comments for California is that we have these plants that were talked about this morning, and I've just highlighted these in one slide. The hydrogen energy plant with petroleum coke and EOR, that's commercial scale, a very large scale at the 250 megawatts of electricity, the 2 million metric tons per year of CO2 scored.

There's a lot of attributes to this approach. One of them is hydrogens that intermediate gives you that enabling technology for the fuel cell vehicles, is getting into that transportation sector for the long term. And you may recall that slide I showed for California, the biggest CO2 emissions here aren't for power generation, they're for transportation. So we have to look at low-carbon fuels for transportation and this is one option. And being a solid fuel, the other option is longer term that you can co-fi or biomass whenever it's available. So that's a double reduction.

The oxy fuel is a smaller scale. They're hoping to build a demo with that. Even as that proceeds right now, they still have the successful pilot plant where they do have a source of CO2. The beauty of the clean energy systems with the oxy fuel is that you can build this without stack at all and makes permitting much easier for these zero emission plants.

Also, on oxy fuels, Petrobras in Brazil is developing oxy-fired fluid cracker in one of their refineries right now. So that's one thing to follow as well.

Let's see, a controversial thing I have here, this last point, is that we don't have any demonstrations at this time of -- and that's a typo there, it should be post, I made a mistake in that slide, but we -- I think we really need a post-combustion pilot in California, especially on natural gas because of our natural gas use.

Now, in North America, most of the post-combustion, I apologize for the typo, that should be post, most of the effort there has been coal based. But if you look in Europe, a lot of the European and the Middle East work on CO2 capture and storage has been post-combustion of natural gas. So we can follow what they're doing. In particular Abu Dhabi has very high plans, or very large plans for a natural gas-based, post-combustion, commercial scale plants as well as some in York, too. So those are the places we can watch this post-combustion. I apologize for the typo in that slide.

So to summarize, we have 30 years of commercial experience with CO2 capture and storage in the United States.

And all of that has been in enhanced oil recovery, 3,000 miles of pipeline, as large as 32 inches, all running very successful. About 20 percent of that CO2 is from anthropogenic sources. So it's commercially available out there now for this niche market, but we have to expand that into saline aquifers for the large reductions that we hope for for the long term.

Pre-combustion tends to be the most developed. It has that application of hydrogen as the intermediate which gives you the abilities to go into transportation where steam limits you just to central power plants. On the gas location, the S&G are the polygeneration where you have the CO. The co-gen gives you advantages over central power plants.

The post-combustion, the oxy combustion tends to be less developed, but there's a lot of movement at this time in this area. They're moving very quickly to gain on the pre. There's simpler technologies. You can retrofit these and there's something that the power industry is more comfortable with than gas location.

The cost of the CO2 capture and storage, they tend to be controlled by this large investment and the energy loss. We need to improve those costs and we need to do it in getting both demonstration plants and advanced technologies going as quickly as possible.

California, I think, has even a higher cost associated with the CO_2 capture and storage mainly due to our lack of coal use and our dominant natural gas use for power generation and our high natural gas costs, those will tend to be high.

We do have the advantages, though, of the geologic formations. They're very attractive for storage along with the enhanced oil recoveries, both EOR, CO_2, but also the steam stimulation EOR of heavy oils for co-gen. So I think those two can neutralize these higher costs in California to give us an advantage to move on CO_2 capture and storage.

So I hope I can answer some questions and there is a lot of things in those slides I didn't have time to talk about.

MR. MYER: We have time for a question or two. Geir.

MR. VOLLSAETER: Thanks, that will be a nice lead-in for me as I go on after you, but you've looked at specific plants, be they predisposed or oxy combustion. You looked on deploying them in California with additional local cost, as it were, of 25 percent.

When we look at the incremental costs of a kilowatt hour dispatched into the grids, what analysis have you done, or have you done any analysis, say, by adding four gigawatts of natural gas combined cycle post-combustion, distributed that over the total consumption and what that would look like?

MR. SIMBECK: Okay, I have not done that, and I want to make sure I understand your definition. Your definition is strictly the operating costs on the marginal low dispatch having nothing to do with capital charges?

MR. VOLLSAETER: That would be all in.

MR. SIMBECK: All in.

MR. VOLLSAETER: All in.

MR. SIMBECK: It would include both the capital recovery as well as the --

MR. VOLLSAETER: Reasonable costs and everything else.

MR. SIMBECK: -- the variable cost, okay.

MR. VOLLSAETER: Yes.

MR. SIMBECK: Okay. I've looked for some of those, but not California specific. But the way I have my models set up, I can do that rather easily and make it very transparent.

I would caution you that in a carbon-constrained world, all our analysis shows that natural gas is a big winner. And so, as you bring in more carbon tax and try to get reductions in CO_2, that natural gas price will be going up. And so that's going to impact this marginal low dispatch of these natural gas plants and would tend to favor these petroleum coke plants at the very low, marginal low dispatch.

MR. BIRKINSHAW: Larry, I have just a couple of questions. First of all, I was a little late, I apologize. When I first came in, though, I think you were talking about pre-combustion. And I believe you said that there are a number of facilities around the world employing this pre-combustion technology, but also they include carbon capture.

Is it -- what, I guess -- is that true? Did I get that right?

MR. SIMBECK: Yes.

MR. BIRKINSHAW: And what are they doing with that carbon? Are these CCS projects?

MR. SIMBECK: No, no. Most of them just vent the CO_2. They get the pure CO_2 stream and just vent it. It's not being done to take out the CO_2. It's being done to produce the pure hydrogen stream which the plant's build to do.

And so it's very hard to go around the world and find the gas location plant that doesn't remove most of the carbon. But most of the plants, after they remove it, just vent it. There's a few plants that are recovering that CO_2

into storage, the biggest being the Great Plains Gasification plant in North Dakota that sends their CO2 up to Canada to Weyburn for enhanced EOR.

MR. BIRKINSHAW: And another question. On your slides regarding costs, I believe you said that the cost of electricity could go 25 or 30 percent with carbon capture and storage. I'm wondering what basic assumptions you were making about technology and is that existing technology? And what do those costs look like if some of these emerging technologies, such as chilled ammonia, become viable alternatives?

MR. SIMBECK: Excellent question. That's based on the commercial technologies now. And the costs on those tend to be high right now, both due to the escalation in costs the last three years which are now starting to come back down, but also due to risks of first of the kind plants with a lot of contingencies and conservative designs.

So the -- there's two things that are going to bring down costs, learning by doing on the commercial ones, but also improved technologies and then commercializing those. How much will come from each is always of great debate. And if you talk to any researcher, it's always advance technology, the technology of the future forever. And the problem is forever. And you talk to the commercial people that we need demo plants and the truth is somewhere in between. You do need both; learning by doing and constantly improving and working on advance technologies. But be honest to yourself how long it takes a pilot technology to get to commercial acceptance. There's quite a learning curve there to gain market share.

MR. MYHRE: Rich Myhre, BKI. A nice presentation, Dale. Also in the news a lot are the novel capture technologies; algae and membranes and things along those lines. I'm of the opinion that there's a gap, developmentally, between the sorts of processes you're talking about and before any of those will be reaching a commercial scale. Can you comment on your opinion on that?

MR. SIMBECK: Yes. There's headlines every week on advance technology that's been thought about in a laboratory. And some of these are not going to make it. I would say, traditionally, you know, nine out of ten will not make it to commercial scale, maybe 99 out of 100 won't. But you want to pursue those and constantly keep whittling down the ones that still have potential and then move those as quick as you can into pilot plants, demonstration and commercial plants.

So there's always new technologies coming that look exciting. As you get into it, though, you have to be honest to yourself which ones don't make it. And actually, you learn more from being wrong than being right if you're honest about why certain technologies didn't make it. And you learn from that through the others.

So we need both and I don't think I can answer your question directly in how and which are going to be the winners here. There are some exciting ones right now that are coming along quickly. The chilled ammonia is one. The, you know, some of this advance oxygen combustion work where you don't have the air separation plant, where you have the metal hydrates being circulated in a circulating cooling bed. Those type systems are moving quickly as developing systems.

MR. MYHRE: Thanks, Dale.

MR. MYER: Thank you very much, Dale. So the -- we'll move on to the next talk which is by Geir Vollsaeter. Did I butcher the last name? Sorry. And it's about California's low-carbon fuel standard and opportunities for CCS. Thanks, Geir.

MR. VOLLSAETER: Thank you. Good afternoon. And being at the tail end of this, having gone through some regulatory issues and also technical issues, I'll try to -- I've covered some of that in my presentation, but I'll try to highlight a few things that can come in addition.

As you might see from the name, I'm not native, but I've spent a decade in this state and here in Sacramento and it's a pleasure to be back. The other thing that's maybe worthwhile mentioning is that I worked with the CO2 capturers, CO2 management for about a decade. I'm also in renewables and biomass. And had the fortune to be able to work on carbon capture and storage projects from natural gas, coal and other things.

And what's happening with regards to regulation and the drive towards lower carbon intensity, both in what we consume in terms of fuel, power, steel, aluminum and the likes is terribly exciting and it also enables us to get a much, much better view on the life cycle of the things that we consume. And in that regard, California has gone, by far, the longest in terms of setting an EPS Board or Mission Performance Standard for power. And also developed a Low Carbon Fuel Standard.

And so, I will talk a little bit about CO2 emission reductions in the value chain of fuels. And I will focus primarily on oil and gas and I'll touch upon hydrogen as well.

As has been said here, my experience is that we capture and release CO2 today. So I know the technology works, but we're not getting in the ground. And there are show stoppers out there that makes it hard. And some of those have been highlighted today with regulatory issues, lack of testing and often times, long lead times in order to get these projects to fruition.

Last year, there was an outcry in South Africa. That's because their coal to liquid facilities were down.

MR. BIRKINSHAW: Excuse me, could you speak up just a little. I think there's some having a hard time hearing you.

MR. VOLLSAETER: All right. There was an outcry in South Africa because there coal to liquids where they convert coal into diesel were not operational. And those plants supplied CO2 to all their Coco-colas and their Pepsis and everything else. No ad, or advertisement here, but it caused a disaster in the drinks industry because the CO2 that was supplied from these processes weren't made available. And it tells you that CO2 is a commodity in places and that CO2 is being taken out of these Syngas processes, which Dale so well explained, are in operation today.

In terms of the technology that we have, in terms of capture, its transport and storage, it is not, in my view, a technology issue. It's operations, good operations, stewardship and all those good things that have been mentioned today. But in the end, where we put the CO2 is of utmost importance. And doing that work upfront, which

WESTCARB is part of, is absolutely critical.

I've been involved in projects where we've drilled wells in other places in the world and they have come up not being the right ones. Either their rock has been too tight, been too expensive to inject and a variety of reasons. And so you walk away from those. But you need to drill in order to figure out whether you got good storage. And I'll get into a little bit about the storage potential here in California but also elsewhere.

A critical thing that when it comes to costs, I've benchmarked the cost of CCS, carbon capture and storage, up against a kilowatt hour, you know, an incremental cost or the kilowatt hours you purchase. And you can do the same thing in terms of, you can call it -- in terms of a barrel of oil or a ton of steel or, you know, if you relate it to the product price, it looks different.

So whereas it could be a lot per ton of CO2 sequestered, it might mean a marginal increment or cost for certain products out there. And that's worth all keeping in mind.

The Low Carbon Fuel Standard, which I'm sure those of you from California that are sitting here, probably doesn't need much explaining, but it measures CO2 from its upstream production and as it ends up into the transportation sector.

The various point sources that you have from the production of hydrocarbons and to where it ends up in the car is very amenable to CO_2 management in several places. There's two particular places and that's in the upstream where you produce.

Canadian oil sands have been raised here earlier today and it's been debated for a variety of reasons over a long time. It's fairly carbon intensive compared to some processes, but less carbon intensive than others that I'll show.

But in the upstream bands, what I call the downstream and the refining of these fuels is where we can have significant benefits and I'll show some examples of that a little bit later on.

This is a slide that I've borrowed from Total. That's the French oil company. They have a carbon capture and storage project operating today in Southern France. I believe that is a oxy fired project, very small scale, but in Southern France, but they've had success in storage. They've developed this slide and it tells you, I'm going to tell the story about it. And if you look to the left, conventional oil, it's easy to produce, it's easy to refine, it's not very CO_2 intensive. The lowest CO_2 intensity barrel you can produce today is probably around five, six, seven kilos of CO_2 associated per barrel by the time you get it into the market.

As you walk up the line of enhanced oil recover, San Joaquin heavies or you go to Venezuela or other places around the world, the carbon intensity increases. The energy inputs that's required to get the barrel out increases. And the energy you use in can be a good source or way you address the emissions.

The Low Carbon Fuel Standard have gone through most of the technical background work and there's volumes of it. And it's interesting to read. And if you go down the value chain of where you get your energy from, you will see that although pipeline gas can be a clean and used product. For us Europeans, by the time you've hauled gas out of Siberia, across Russia, through the Ukraine and into Europe, by the time you have some methane leaks, a lot of compression, you will see the carbon intensity increase as it comes in. You'll see liquid natural gas here. That's a global commodity that travels around the world. It's conversion can have 25 to 30 percent losses in conversion. And by the time you bring it in, that needs to be factored in and that's what the Low Carbon Fuel Center does in principal. But in terms of using natural gas or compressed natural gas for fuel, that comes in.

Far off to the right, is what's being considered for coal and Dale mentioned this, as you do the Syngas process off of coal, you can convert it to diesel or a range of different products. This technology has been around for a very long time and the CO_2 can easily be taken out and it's the storage part of it that's challenging.

But what it tells me is that the carbon intensity of the upstream is increasing over time simply because the low hanging fruits of light oils and easy hydrocarbons at that time is pretty much over. Hence the transition.

The opportunities that exist within Low Carbon Fuel Standard and AB 32, is the CO_2 reductions can be had through CCS. So far, I've figured out that AB 32 allows for those reductions to be counted in.

I'm left a little uncertain whether if you take the CO_2 as a -- through carbon capture and storage from a refinery, whether that's eventually counted as a reduction in the fuel you're supplying out. And if that is the case, we have a challenge where reductions that could be had here in refineries might not be given credits of the final fuel that you deliver out into the market. If that is not resolved, we could likely undertake projects here, but where maybe credit is needed, credit is not given. So maybe a little regulatory tuneup to that process is needed.

The last report put this out, CCS out in the future, towards 2020 and maybe out towards 2050 and due to commercial costs, but looking at the cost of doing nothing, as I mentioned in my first slide, that's one that can be revisited. This is not a technology issue, it's an incentive and compliance issue.

The other major, major upside I see to a lot of carbon capture from both power plants and refineries is that by the time you strip the CO2 out from, be that the Syngas you produce or any other process, you will need to remove particulates, NOx and SOx and other type pollutants.

So the net gain is not only taking the CO2 out and sequestering it or storing it, but you get other benefits in local air quality as well.

So looking upon this, not only as a CO2 opportunity or as a challenge, you look upon the other included benefits that comes from these processes.

The American Petroleum Association have produced back in 2004, and I doubt it has changed much, a breakdown of the average refinery portfolio in the U.S. and where the point source emissions are. These sources are all amenable to carbon capture but at greatly different costs.

Hydrogen production, on the average, in the U.S.

counts for 10 percent. But due to the slate of crudes that California refines, the CO_2, the hydrogen requirement for refining here is much higher. Hence, the CO_2 emissions associated with hydrogen production here will be higher in order to provide the standard of quality of the fuels that California needs and requires.

Another 35 percent of the emissions from a refinery comes from the cracking process. And refineries will have different systems in place to break down the crude into usable products. But I'll bring a couple of slides on that a little bit later.

And the other emission, the largest emission by far is the combustion processes. That's utilities such as generators and boilers that provide steam and other useful inputs into refining fuels.

But you can understand from this slide, just by going after the CO_2 that comes off that Syngas process when you steam or form hydrogen can lead to a significant reduction of CO_2 from a particular refinery, just from the hydrogen alone. By the time you address the cracker, you're talking substantial reductions. And by the time you do this even 10 percent on the Low Carbon Fuel Standard from the well to the tank, your emissions will drop significantly because refining in California is a significant input per unit energy that's delivered out into the market.

By this nice graphic from Conoco Phillips, this catalytic cracker that they've shown for an example is a 50,000 barrel a day cracker. With 90 percent capture, you can take out 1,000 tons a day of CO_2; 360,000 tons a year with operational time from one cracker at 50,000 barrel a day. Refineries in the U.S. range from, you know, the smaller ones, 20-30,000 a barrel a day, probably up to 250-300,000 barrels a day to the largest ones. And if you add it up, this is a very large, single source point.

The challenge with addressing a cracker is that the gas quality that comes off there is not easy to deal with. This is a major technological challenge that can be solved because engineers knows how to do this. It can be solved, but it's an expensive source to go at and it's going to require innovation and deployment in order to get comfortable with the quality of gases that are mixed together with the CO_2 when you try to strip out the CO_2 for storage.

Hydrogen production. Ninety percent of California's hydrogen comes from natural gas and by-products from the refinery. In this process, you can see on the bottom that in order to produce the hydrogen to the quality you need, you need to strip the CO_2 out. And this CO_2 today is not in very high concentration, but it's stripped and vented. So this could be an opportunity at numerous refineries where additional concentration of the CO2 that comes off of the CO2 removal process here is used and put into a pipeline system and injected into suitable storage.

The other part that links into the Low Carbon Fuel Standard here is if we are to provide hydrogen for the hydrogen highway here in California, by the time you take CO2 out of hydrogen produced in a refinery, you lower the carbon intensity of the hydrogen fuel sector. There is a requirement now as far as I understand of 35 percent requirement for a bio-fuel feed-in into the hydrogen future. If emissions reductions from this process which happens at just about every refinery and independent hydrogen producers were allowed into a Low Carbon Fuel Standard, the reductions, then, would be passed on through the fuel as it's delivered in.

So, together with carbon capture off of hydrogen reformers and with the bio-fuel inputs, you get an even lower carbon footprint for the hydrogen, compared to electrolysis of hydrogen which is commonplace in many other places around the world. But if you fuel that with the carbon intensity of electricity, the net gain or the net loss is quite significant because the conversion factor for the electrolysis is really low compared to steam reforming as you see here. And if you use unmitigated coal, conventional coal power, your carbon intensity is going to be significantly higher.

So strategy choices around how California fuels its hydrogen will be important and I think CCS around hydrogen production integrated in these refineries is a significant opportunity.

One slide ahead of the game here. California refines about 2.1 million barrels a day. And the annual emissions are close to or above 17 million tons a year. The data that I got from WESTCARB indicates that the associated emission from hydrogen production is seven and half million tons. What I read in AB 32 and in the efficiency gains from flaring, AB 32 identified one and a half million tons in flare-outs methane reductions. That is in the plan.

Other incentives to enable access to these seven and a half million tons around these hydrogen reformers would greatly enhance the emissions reductions that could be made available from these refineries.

An example from Norway, up to the right you'll see the Mongstad Refinery. It is part owned by Statoil, I think, 78 percent and Shell Oil owns the other 22 percent. The Norwegian government has decided to fund about 80 percent of the cost to get CO2 stripped off this refinery from two sources and inject it into the offshore.

This flow chart tells you where the emissions are. Back in 2002, the refinery was in the fourth quartile, meaning an under-performing refinery in terms of its energy efficiency. The refinery then decided to install a combined heat co-gen unit on the refinery in order to close down a lot of small boilers. That brought the refinery up to almost first quartile which means a very good energy efficiency index globally.

But given that normally has a particular focus on CO2 capture and storage, the government has required CO2 capture off of this facility. So these are the plans that have been developed and that is to strip out 870,000 tons a year of CO2 from the cracker at the refinery. And another 1.3, almost 1.4 million tons from the combined heat and power unit which is natural gas powered.

Combined and compressed, this will yield almost two million tons of liquid CO2 per year to be injected into the offshore. Theoretically and technology-wise, this can be done. The costs are significant and if California has a location factor of 25 percent, Norway has one of 85 percent. So by the time you move equipment from the Gulf Coast and bring it to Norway, it's a cost penalty to 85 percent.

But Norway's in the fortunate position of producing almost a barrel of oil per head per day. And so there's money there to be able to undertake this. And it's by far the most expensive mitigation project you can get anywhere. But the innovation that comes from, and the learning that comes from deploying capture at the cracker units and as well from the combining power units in a post-combustion mode will be significant.

I know that Alstom, which Dale mentioned, has successfully last week, I think, declared that they had success in Wisconsin with their chilled ammonia technology and I think they're into quantum technology (indiscernible) race for this particular project in Norway.

One more slide on technology. They look the same, but the difference between these two is that one is pressurized and one is non-pressurized. So essentially, the technology, we'll see down to the left, is in use today all around the world and here in the U.S. onshore and that to essentially strip CO2 out of natural gas that's produced that has a CO2 content too high to meet pipeline spec.

This is deployed all over the world and I think there are some 900 facilities like this that essentially conditions natural gas to where it's sellable into the market. Two and a half percent CO2 in natural gas is standard spec pretty much anywhere in the world.

Most of the gas you'll find these days, they might be deep, they might have H2 gas in it, might have CO2 and that has to come out. And that's why this technology is deployed. And it's an operation at many gas processing facilities around the world.

Taking that process over to a non-pressurized situation is basically a similar process. But you will have much, much larger efficiency losses, which Dale went into detail about.

When it comes to storage, Norway has undertaken CO2 storage and oil -- not in oil sands, but in sandstone which California has plenty of, since 1996. They've injected about a million tons from an oil and gas field -- or a gas field called Sleitner. This storage -- the formation is, I think, 250 miles long, is between 30 and 50 miles wide and is 150 feet thick. It can store most of Europe's emission for 100 years, all in. That's only estimating one to two percent of the total pore space available in that one formation. So it's not -- we're not talking over pressurizing this reservoir with that estimate.

So, we remain confident that there's ample storage. And from what I've seen from WESTCARB's investigations, this can be the same, but in order to verify this, pilots, like they've done in Norway, or this is a commercial operation here, needs to be undertaken here, too. It's a scale where confidence is built up.

Norway has two of these facilities in operation and I think there are only three large commercial scales with the injection processes globally to date which are pure storage and saline formations. And two of them in Norway, the other one in Algeria. I think that's the operating facility.

These are the data that I'm sure California would like to have had as well, is a time series of seismic monitoring of CO2 stored in the sandstone. This gives confidence and it gives -- essentially you verify where the CO2 is at and where it's going to migrate to over time. This can be modeled.

If you mapped this little plume of CO2 in this formation that the CO2 is in, you won't even see it with a pinpoint. It's that small. But these are not large volumes. It's about a million tons per year that's been injected since 1996. Mega-scale coal plants, five-six tons per year, radically more.

Another project that I'd like to mention is that CCS offer refineries or capturing CO2 from refineries has been in operation elsewhere. And that's in the Netherlands and Shell has a refinery there called Pernis where CO2 is taking off these processes inside a refinery and it's piped, and the green line you see here is the existing CO_2 pipeline that a third party built to supply CO_2 to greenhouses. The benefit of that is that they will not need to use CO_2 or natural gas for the growing process. So they displace natural gas in the summertime to the equivalent of 170,000 tons of CO_2 savings per year. That's quite substantial.

There are significant developments in this area. You can see it's densely populated. But this project has now, I think with the Rotterdam Port Authority and a number of other stakeholders, there are plans to significantly expand the amount of CO_2 that's put into a pipeline infrastructure network. And as you see down at the bottom, there's a field called bottom index, and there are plans now to, which is the depleted gas fields, there are plans to inject CO_2 into these fields for pilot purposes.

Back to the Low Carbon Fuel Standard. One thing is verification in the subsurface and the other is how do you measure what actually goes in from source to where it's finally and safely stored.

To date, there aren't any protocols that are commonly accepted or approved that makes that process go smoothly. So at present, a company here in the U.S called Bluesource and the North American Carbon Capture and Storage Association has initiated some work to develop protocols to where you can measure CO_2 from when you have it in the upstream and bring it down to final storage. That is important in order to verify the credits that should come from this.

My final remarks, I'm going to jump straight to the bottom. I'm out of time. With regards to the earlier reports, I deem this as an issue now that is not a technology issue, it's a cost issue. And knowing the lead times, which could easily be four, five, six years to get a big project up and going, ensuring that the regulatory certainty is put in place in the terms of the subsurface when it comes to liability or stewardship as some people like to call it, is crucial before you start to get larger developments going.

With that, I'm going to close it up.

MR. MYER: Thank you very much. Questions? Okay, Geir, we thank you very much. So, I think we'll have one last talk before some open discussion from Mary Jane Coombs about the AB 32 update and opportunities for CCS. Mary Jane.

MS. COOMBS: Thank you, Larry. As many of you have heard, AB 32 referred to today and I'm going to talk about something that was required from the Bill AB 32, which was the scoping plan and the ongoing implementation of that and how geologic sequestration plays into that.

So it AB 32, as many of you know, was signed by

Governor Schwarzenegger in September of 2006. This followed, by about 15 months, an Executive Order that had been signed by the Governor, not quite requiring, but encouraging California to reduce it's greenhouse gas emissions to 1990 levels by 2020 and going beyond that, to reduce 80 percent below 1990 levels by 2050. AB 32 specifically address the 2020 issue and I'll be talking a little bit about the difference between those two goals today.

So AB 32 directed the California Air Resources Board to develop a climate change scoping plan which would lay out how these reductions would be made. A draft copy of this plan came out almost a year ago. It was adopted by our Board last December. So it had been through about two years, a year and a half of a lot of public meetings, a lot of input from our sister agencies, especially the CEC, the CPUC, Tarp and the water resources, the Waste Board among many others.

And this plan recommends a broad mix of strategies for making these reductions. Several of them include market mechanisms, a cap-and-trade program in particular, direct regulations for reductions, volunteering measures. Energy efficiency is specifically drawn out in the plan and then some fees.

And as I mentioned before, that the key goal of the scoping plan in AB 32 itself is to reduce greenhouse gas emission levels back to 1990 levels by the year 2020 which, as we know, is coming up pretty darn quickly. But the scoping plan also looks at measures that will not just enable the State to meet these 2020 levels, but that will make it easier for us to meet the 2050 levels.

So I don't -- I actually don't think we've seen this -- I wasn't here earlier in the morning, but I don't think we've actually seen this pie chart here today, but it shows the 2002 to 2004 greenhouse gas emission levels for the State. And I just wanted to -- I'm going to focus on three different sectors: the transportation section which is responsible for about 38 percent of those emissions; electricity section, about 23 percent; and then the industrial sector.

Here's a visual for you of the challenge facing the states. On the very left, and I hope you can see this better than some of the slides today, I know the light's a little iffy, but the 1990 emission base-line that we are looking at and need to return to by 2020, is 422 million metric tons of CO2 equivalent. This is about a 169 million metric ton reduction from business, the calculated business as usual. And then you can see the dramatic reductions that will be needed to meet those 2050 goals. Quite huge.

And specifically, looking at the scoping plan, I have an outline here of how the different measures on a sector-by-sector basis contribute to those reductions over time.

So these are business as usual, total emissions for 2020. You can see the large contributions that transportation, electricity, industry, natural gas make to the emissions overall. I'm just going to sort of bring you through some of these. On the right, there are -- there's a general outline of which particular measures are contributing to the reductions outlined in the scoping plan.

Now, a large part of the scoping plan reductions come from a greenhouse gas cap-and-trade program, 20 percent of those reductions. And those are going to cover the transportation. By 2015, they will cover the sector of transportation, electricity, natural gas and industry. So if you look at those on that bar on the right side, under total emissions, 456, those are the bottom four blocks there. They're going to be reduced down to those three -- or four sectors, excuse me, are going to be reduced down to 365 million metric tons of CO_2 equivalent.

So I spoke a little bit about the fast time line for reaching those 2020 emission levels. We're on an even faster time line to adopt the regulations for all these measures by the end of 2010. So we have a year and a half. ARB uses a very formal structure that is used for many areas to elicit public input on this regulatory process. In fact, this afternoon, there is a meeting on the use of set-asides within the cap-and-trade program being held over at ARB on -- if you're interested in offsets at all, on Thursday afternoon, there'll be another public meeting on that. And that just happens to be, I work within the cap-and-trade group at ARB and there are, in any week, probably at least half a dozen public meetings on any of these different measures that I'm going to take more about in a moment.

So we're very interested in reaching out to our sister agencies, stakeholders. We're especially interested in involving the Environmental Justice Community and this is a requirement of AB 32 and it's part of ARB Continuing policy as well.

So these regulations will be taking effect by January 1st, 2012. There are a number of early action measures that will be in effect before then, but January 1st, 2012 is the deadline for all of them.

AB 32 and ARB Policy in general outline a number of requirements for any of these scoping plan regulations or measures. As I mentioned before, public process is a very part of that. We have to minimize costs of achieving these reductions and maximize benefits, in particular environmental benefits. We need to protect low income communities. This was, for the market-base, compliance mechanisms are the cap-and-trade program. This was especially called out, minimizing those impacts.

And then we -- because we traditionally have been an agency that has regulated smog and air toxics, we want to make sure that these greenhouse gas reductions we're seeing aren't causing any issues with our existing programs.

And then, of course, because greenhouse gases are global in nature, we don't want there to be any leakage in those emissions out-of-state. We also want to make sure that we're not discouraging businesses from operating in this State. We want to continue to have a thriving community, business community. So we want to minimize all sorts of leakage.

And then, finally, we don't want this program to be so difficult to understand that businesses end up throwing up their arms trying to understand how everything fits together. So we want to minimize that administrative burden of the program.

So there have been a number of laws and regulations that have already been adopted in relation to AB 32 and the scoping plan. A key one of these that you've heard a lot about in the media over the past year or two is the Pavley AB

1493 automobile role of the tailpipe emissions standards which we are waiting with bated breath for a waiver from US EPA for go-ahead to implement that program.

But we have a number of others that have been -- regulations that have been put into place within the past year or two. Most recently the Low Carbon Fuel Standard just last month. High global warming potential gas reductions. SB 375 was a bill that was passed within the last year that looks at regional targets for greenhouse gas emissions. We have an advisory committee working on that. But this just gives you an idea of what's already been going on and we almost feel like we've just dipped our toe into the pool of these regulations.

So over the next 18 months, ARB alone has 20 measures scheduled for the next six months and 13 measures scheduled to go to our Board next year. The cap-and-trade system regulation will be waiting until the very last minute because it's such a complex system. That is scheduled to go to the Board either November or December of 2010. And then there are 21 other measures with other state agencies including CEC, CPUC, Department of Water Resources, et cetera. And if you're interested in any of those in particular, I have more detailed information and can talk with you off-line about that.

But the big disclaimer is the schedules can and likely will change and some measures, in fact, may be added or dropped, depending on any new information that comes to light as we learn more about accounting of greenhouse gas emissions and so on.

A key part of AB 32 was requiring a greenhouse gas inventory and reporting. The inventory actually started here at CEC and we have estimates for emissions that go through 2004, starting in 1990 through 2004. And those estimates, those 1990 estimates, were what was used to establish that target level for 2020. And hopefully any day now, the inventory numbers for -- excuse me, 2004 and beyond will be released.

And about a year and a half ago, the Board approved a regulation for mandatory greenhouse gas reporting. This will come into effect this year requiring reporting verification of greenhouse gas emissions from a number of different sectors.

Very broadly, the requirement is for any source greater than 25,000 metric tons of CO_2 or power plants greater than 1 megawatts and 2500 metric tons of CO_2 to report. I will caution you that this will be changing, though. The cap-and-trade program which is going to link to a regional program through the Western Climate Initiative, the WCI standards are 10,000, reporting from facilities that have 10,000 metric tons or greater, CO2E. So that will be part of the cap-and-trade regulation process over the next year and a half.

By the end of next month, facilities that are required to report must submit their 2008 emissions unless they are going to have verified emissions and I believe they have until December to report those. And then starting next year, the emissions for the previous year must be verified by an accredited third party.

Okay, getting into the three major sectors that we're looking at for the emissions reductions to come from. Very quickly, transportation, as I mentioned earlier, counts for 38 percent of greenhouse gas emissions, approximately, depending on the air. And a big part of those reductions are going to come from the Pavley Bill reductions. There's sort of an advanced Pavley Bill also being considered and then we have the Low Carbon Fuel Standard which was recently adopted.

The reductions from electricity, we're hoping that they will be quite large. While there are approximately 23 -- 23 percent of the overall greenhouse gas emissions come from electricity, both in state and out of state, we're actually looking for more reductions to come from the electricity sector. A few of the majors that are in the scoping plan include looking at zero net energy buildings, stringent building codes. Our new portfolio standard is a key part of that, 33 percent renewables by 2020. And a very key part of it is energy efficiency, becoming more efficient.

And since we're at the Energy Commission, I think this is -- anybody who has been in this building before for our previous meeting knows that energy efficiency is a big part of the programs here. And that will continue to be a big part of greenhouse gas emissions reductions.

And then the industrial sector, which is responsible for approximately 19 percent of greenhouse gas emissions, is looking at a number of rather small reduction measures. I believe it's something like 1.4 million metric tons of CO_2 equivalent in reductions by 2020.

And these, just to go over them generally and briefly, energy -- we are requiring an energy efficiency and co-benefits audit for large industrial sources. So this would include, important to CCS folks, power plants, refineries and cement plants emitting more than .5 million metric tons of CO_2 per year.

We're looking at reducing methane emissions in oil and gas products, reducing leaks in gas transmission and from incomplete combustion, limiting the emissions from refineries, refinery flares, excuse me, and then removing the current fugitive methane exemption from most refinery VOC regulations.

As I mentioned earlier, the cap-and-trade program is a very large part of the program for reducing greenhouse gas emissions. And I want to -- a key point I want to make is that the cap that I'm going to be talking about is a subset of the statewide target for 2020, whereas the target -- actually, I have the wrong number up there. The target for 2020 is 422 million metric tons of CO2 equivalent for all sectors for all of the economy. The cap for the four sectors I mentioned, major industrial sources, transportation fuels, residential/natural gas fuels and electricity is 365 million metric tons of CO2 equivalent.

So, there are going to be two sort of phasing periods for this cap-and-trade program. At the start of the program in 2012, electricity generation, including imported electricity in large industrial facilities, will be included in the cap-and-trade program. Starting in 2015, we will add upstream treatment of fuel combustion. So, at those facilities, small industrial facilities where you would have less than 25,000 metric tons of CO2 per year being produced, that would be included as well. And, of course, transportation fuel use.

So this is -- this graft just gives you an idea of what the reductions would look like. The scale, I don't include a Y axis scale because we have not set the caps for -- well, the caps for 2012 and 2015, but the idea is that electricity and industrial sources are included in the cap-and-trade program between those periods. And then the cap will be raised starting in 2015 for inclusion of the transportation fuels and the natural gas fuels upstream. And then reductions occurring overall until 2020.

The view with the cap-and-trade program is that the majority of the reductions will be met through the direct measures involved in the scoping plan. So the renewables portfolio standard, the Low Carbon Fuel Standard. Energy efficiency measures are going to allow businesses, allow emitting facilities to make the most of those reductions. And then the carbon -- the price that is put on carbon on top of that will further encourage more reductions to be made.

We are going to allow some use of offset credits from uncapped sources. So, say, if there's a forestry sector project that is able to prove that they are reducing greenhouse gas emissions, some of those credits could be used for compliance within the cap-and-trade program. But those will be quite limited. They will be limited to a max of 49 percent of the reductions of greenhouse gas emissions.

So the idea with the cap-and-trade program, that the benefit, we see it as providing, compared to a carbon tax, is that, one, there is an absolute limit on the number, on the amount of greenhouse gas emissions which would not happen with -- likely not happen with the carbon tax. And then, it also allows sources to seek out the most cost effective reductions.

We are not -- California is not in this cap-and-trade idea alone. We belong to the Western Climate Initiative with six other western states and four Canadian provinces. The partners of the WCI are shown in green. The observers, those who may in the future become partners, are shown in yellow.

And the idea here being that not only can we achieve greater reductions and emissions by complimenting each others efforts, but also that we can minimize leakage by having a program that goes over a broader area.

All right, finally to which you really want to hear about is what does the scoping plan say about geologic sequestration. The scoping plan, first of all, acknowledges the great research that has been carried out by WESTCARB. And it does recognize the potential for utilizing CCS for emissions from a number of different sources. And encourages the State to support, and I'll just quote here, “California should both support near term advancement of the technology and ensure that an adequate framework is in place to provide credit for CCS projects when appropriate.”

Now, here's the key that -- you're probably wondering why, you know, why aren't there CCS majors in the scoping plan itself. Well the ARB views CCS primarily as a 2050 reduction technology. That's not to say that CCS could not provide reductions by 2020, but as you saw from the schedule earlier, we have a very large burden on our plate, challenge on our plate within the next couple of years. And we're looking primarily at the very low hanging fruit to achieve the reductions for 2020. That said, we certainly what to encourage projects that would enable reduction, those huge 2050 reductions to take place.

And just to let you know a little bit about tracking the scoping plan progress, if you're interested in the means that we have, I'll have our website address at the end of the presentation. I encourage you to go there. It's always up-to-date with the numerous meetings that we're having.

But we're also working very closely with the state's Climate Action team to make sure there's consistency across the many state agencies working on this to especially prevent double-counting of any reductions. And my office and other offices within the ARB are updating our Board twice a year on progress and all our board meetings are available on the web if you ever want to check on those. In fact, we have an update coming up at the June board meeting. I think it's the 26th of June.

And I did, particularly I want to call out something that a project that we're starting work on with NARB's research division. And Elizabeth Sheehle is here today if you have any questions about this. We have a greenhouse gas mobile monitoring -- well, a number of mobile monitoring platforms. And the purpose of these platforms is to, one, generate emissions factors for poorly characterized greenhouse gas sources which there are a number; and then just support ARB perams in general. And this project that is in the planning stages is we want to utilize these platforms to go out to oil and gas wells and see if we can quantify the methane emission leakage rate, if there's any, and use that as an analog to leakage from large scale CO2 sequestration sites.

And this -- obviously, there -- we can be using this for greenhouse gas inventory purposes as well. So, we think this is a really great opportunity to do some of our own research over there at our agency.

And that top website, I encourage you to check out often for updates. And there's my contact information as well as Elizabeth's if you're interested in talking with us more. I do want to specify, I work for the Office of Climate Change in the cap-and-trade program, so that is my area of expertise. And Elizabeth is the point person in the agency on geologic sequestration. So thank you for your attention.

MR. MYER: Do you have questions for Mary Jane?

MR. BIRKINSHAW: Yeah, I have one question. Hi, Mary Jane.

MS. COOMBS: Hi, Kelly.

MR. BIRKINSHAW: You mentioned that in the cap-and-trade program, there is a provision for offsets. I'm wondering if carbon capture and storage is an eligible activity for those offsets?

MS. COOMBS: Likely no because they would be within cap sectors. Offsets have to occur, the productions have to occur outside of the cap sector. As Rich is coming up to the mike, I also want to mention that because the magnitude of offsets, the tons from offsets are going to be so small, that one CCS project could easily use up all of them. So it's certainly not a mechanism that was built for CCS.

MR. BIRKINSHAW: Well, like I said, there's a total cap on offset tons?

MS. COOMBS: Yeah, that was that maximum of 45 percent reductions. So that's a small number relative to the number of allowances, what we call the allowances within the cap-and-trade program.

MR. MHYRE: Rich Mhyre, BKI. Thanks, Mary Jane. Maybe this is sort of a segway to the discussion portion of the meeting, but I heard what you said, I'm just wondering if you can help me understand it from the point of view of a particular company. Let's say and electric utility.

What I saw is we're going to be obligated to do an energy audit of their power plants and some other facilities. They will have to -- they'll be obligated to either administer energy efficient programs or put out solicitations for third parties to bring in energy efficiency programs. And then a calculus is done and if they still don't meet their goal, then they have an obligation on their own to figure out to get other reductions, either through their vehicle fleets, through some other, maybe, low level heat recovery, activities at power plants or a CCS project. They're sort of free to choose at that point how they meet -- buy emissions from the market? I mean allowances from the market?

I mean, just from the point of view from an individual company. Let's pick electric utility. Walk me through what they have to do and then what happens and if they don't make it, some of the choices they would have.

MS. COOMBS: Okay, you're talking in a sense about the point of regulation for these different things and the point of regulation is different for different measures within the scoping plan.

So for instance, with the cap-and-trade program, they're going to be regulated for -- they -- a source, an emitter will be responsible for the emissions for turning over allowances to -- basically, a permit to emit a certain amount of CO_2 for that facility. So that's not a company-specific requirement.

More, and I'm not as familiar with the individual electricity measures, but that is more likely to be a company-specific requirement. Yes, a company is required to have, you know, this certain mix of renewables by 2020, do these energy X,Y and Z efficiency programs.

So it's -- I keep thinking to that administrative burden, minimizing administrative burden requirement. It does start to become complex, how these different measures interact. But I will say, it will depend on what measure you're looking at specifically.

MR. JOHNSON: Will Johnson, Visage Energy. I guess I -- it's been a while ago, but I read that 350 page scoping document, struggled through it. And I did a search looking for CCS in it and maybe were, at most, eight or nine pages refer to CCS and then you had a chart in there and I couldn't tell whether -- I couldn't read the fine print.

It sort of like had the aggregate numbers that you thought that you would have emission savings from and I was really surprised at the detail, even to the extent of -- one that comes to mind was that some of the boilers at refineries, that you forecast you put in a new boiler and you save X and so forth.

And then I wondered about CCS and particularly to the extent the CPUC has already approved tens of millions of dollars for CCS projects. Edison is looking at a couple. The HECA Project is there. And when I went through the chart, I didn't see any savings that you would expect to come CCS and I thought that was a bit strange and I couldn't quite understand that.

MS. COOMBS: That goes -- you're correct, CCS was not in that chart. And that goes back to the Board viewing CCS not as much of a 2020 technology, a goal to meet those 2020 reductions, but meeting reductions beyond that.

MR. JOHNSON: Well, then, my next --

MS. COOMBS: Actually, let me expand a bit. The measures that were included in the scoping plan are meant to be quite conservative and that was part of the trepidation -- I shouldn't use a word that strong, but the -- because there aren't these large-scale projects going on with CCS, the agency, the Board decided, you know, it wasn't something that would be included.

And we wanted to -- and in particular, we wanted to hit first the low hanging fruit that something was going to help minimize those costs, which, as we saw from Dale's presentation, the costs are relatively high, 50 to 75 dollars per ton of CO2. And the numbers that we're forecasting right now under the carbon cost under a cap-and-trade program, $50 would be the very upper limit.

MR. JOHNSON: Okay, so I guess when I was looking and reading the report and thinking about the logic, you know, obviously, if you're going to meet the requirements of AB 32, you're going to have to capture carbon somewhere along the way.

And so, should you start looking at that today and spending the money, like you said, you know --

MS. COOMBS: Actually, AB 32 -- are you talking about the 2050 requirement?

MR. JOHNSON: Yeah, when you --

MS. COOMBS: 2050 is not part of AB 32.

MR. JOHNSON: Okay. But thinking about if you're trying to get there --

MS. COOMBS: Yeah.

MR. JOHNSON: -- if that's your rule or goal, you know, should you wait till -- or if you're saying, well, we'll wait till 2020 since that technology is not going to be here until after 2020. Or should you be looking at it today? That would then spur it on and sort of like accelerate the commercialization of that technology.

MS. COOMBS: For that exact reason, we are looking at things like the renewable portfolio standard because we want to incentivize that technology transformation earlier. But I do hear what you're saying.

MR. DU VAIR: Hi, Mary Jane, Pierre du Vair with the Energy Commission. I'm curious about some of the economic analysis that CARB is likely to do in the future. There was limited economic analysis done with the scoping plan. Some with the bare model for macro-economics and a little bit with a contract with ICF Consulting. But by and large, i think CARB has said they'll do a lot more economic analysis with each of the regulatory packages.

So given sort of the quick time frame, how are you guys going to accomplish a lot of the economics?

MS. COOMBS: I can't speak too specifically about that since I haven't worked on it all, but part of our problem with the previous economic analysis is we had -- we were hoping to have a couple economic models be able to work together and give us some more specific information and we couldn't do that in the time frame we had from the scoping plan.

But as -- when the scoping plan was adopted by the Board back in December, we did say we would be going back and looking much more closely, working with the economic models that are available to do, a more detailed analysis, for instance, how the cap-and-trade program will play into the economics, how jobs will be effective, how low income communities will be effected.

And actually, this is a very common thing for a regulation in California. We're required to do such an analysis anyway. But I will say that we will be going back to the Board in December of this year with an update on this analysis.

MR. VOLLSAETER: Geir Vollsaeter. When I first started out with the CCS project back in 2002, the unit cost for a pipeline was around $30,000 an inch mile which is an industry term. And we ended up with the carbon capture cost around $30. And we were coming out of a oil price world which was around the teens. I don't know what the coal price were at the time. The same project rolled on and was finally mothballed in 2008 when the commodity prices had quadrupled.

When you do your economic analysis for how you look at CCS and their options for the future, do you do option value? Can you look at ten years down the line and imagine that you're looking at $30,000 an inch mile for a steel pipeline, commodity costs are low, or other types scenarios because the -- in terms of the wedges of reductions needed over time, there is very few options outside, not also including CCS into a long-time framework, knowing that the lead time is almost ten years for mega-projects. How do you envision looking at or redoing or doing the economics for CCS inside ARB?

MS. COOMBS: We will not be doing that in the economic analysis we just spoke about because we're specifically looking at the scoping plan measures. I know that a lot of great work has come out of that through the Energy Commission, through Dale's work as well as others.

So as -- if ARB becomes to the point where we do start looking more closely at that, yes, of course we would take that into account. And I was actually going to say that -- I thought you were going somewhere else with your question, but one of the issues we did have with our previous economic analysis was we used a fixed price for gasoline which was very high at the time. You know, around $4 a gallon. So one of the things we're going to do is we go back, is look at the range of costs. Thank you.

MR. MYER: Thank you very much, Mary Jane. Most people here know that -- maybe a few of you don't, that Mary Jane used to work over here. In fact, she worked in the WESTCARB program. And so, I've always viewed it as sort of a real coup to transplant within the ARB a -- someone who's been working on the CCS issues.

So, I think we've -- we're now to the point in the program where we can sort of yawn and stretch a little bit and decide what to do next. We have a -- two agenda items left and the first of which is an open discussion period. And so we have to sort of figure out how to use that productively with -- at this point in time.

And so, for sure, I want to take this opportunity to have anyone who hasn't had the chance yet to state an opinion about what they have heard so far today. And I'm going to put the -- secondly, I'm going to put the folks who have presented and been part of the panel on the spot and I'm going to identify who they are because the next thing we can do is have an opportunity to either have some further discussion between the panelists and the audience.

And I can see Craig Hart and Elizabeth Burton and Mary Jane and George Peridas and Tiffany Rau still present. So we have -- and we have Geir as well and Dale Simbeck. So we have almost as many presenters as we do folks in the audience which is always an interesting combination.

So, but I don't want to drag this on, too, if we're all too tired and want to do something else. So first of all, sort of formally, I will ask if there's anyone here present, or for that matter, on the Web who would like to ask a question of any of the panelists that we have? And I hear none.

Is there anyone here who would simply like to introduce a discussion item and hear the panel discuss any further issues? Go ahead, Will.

MR. JOHNSON: Will Johnson, Visage Energy. I had an opportunity of chatting with Commissioner Byron before he left and was sharing with him a few ideas that had come up while I was listening to everyone give their presentation. And it was from a banker's perspective. I use to be a former banker lending money to electric generating and gas companies.

And some of us are just like trying to focus on it from a business perspective and we've heard a lot of different opinions here. Some people had a technology perspective, others regulatory perspective. And to me, it seems as though that I think that maybe one of the perspectives that weren't represented here is looking at some of the business-type issues that appear to be neglected which could have an dramatic impact upon how successful the program is.

And I guess, and RDC mentioned that with all the people around the room, we needed a champion. And was wondering who that champion might be. And I think that the champion might be capitalism. And that's the system that can probably drive this to happen. And people are wondering well, why -- where are the bulk of the projects, the EOR projects. Well, I think, you know, with what was happening with the price of oil and gas, you know, it was logical and reasonable that -- that was one of the reasons why that sector got more attention, that would have been the case.

I think that one of the major flaws that almost surprising from a regulatory perspective is that it seems as though the basic concept that renewable energy has cost. And part of that cost is associated with the backup power that's required to, for farming purposes, et cetera. And I'm not sure that ever gets focused on.

And so, the emissions from solar or wind isn't at near zero when you require all of that backup power. And then when you think about the pricing signals that you send to some of the investor-owned utilities is, well, go out and have a lot of inefficient peakers that you can run behind this renewable energy, whereas if they had focused on the optimum type of carbon emissions associated with that renewable energy and looked at CCS as a contributing factor.

And it's almost surprising that, you know, that no recognition is given to that and particularly in a scoping document that was such a far-reaching document in terms of the years out that they were looking at, that that little basic fact hadn't even been considered. I found that a bit surprising.

One of the other comments that I mentioned to Commissioner Byron, and so when I said, well, you know, it seems as though that you would logically offer an incentive to CCS and so therefore, CCS is not really competing with renewables. Actually it's a complimenting, enabling type of alternative if you're attempting to lower the emissions that we're looking at. And then he said, well, how do you pay for something like that? And I said, well, I don't know. Just off the top of my head, another analysis would be like the HECA Project.

Well, if you thought about it from a business perspective, and I was listening to some of your comments and it seems that they're asking, just give us cost recovery. And we shouldn't just be thinking about cost recovery for projects like that. We should be thinking about giving them a profit and having other companies competing with them because there's an opportunity to earn some money because eventually you know where you want to get and you're going to have capture carbon to get there.

And so, I said, just look at some of the little basic economics of the HECA Project. So, okay, you produce this petroleum coke because you have all this gasoline. You're sending -- you ship it all over, all the way over to Asia and the emissions are back here in a couple weeks and so forth.

Well, if you really look at the costs to California and maybe look at, well, what happens to natural gas prices when you do start using? Instead of burning natural gas, look at the savings you have burning that waste product.

I think another issue that would -- that you should take a look at would be the incremental oil that we get produced on an EOR project. Well, who's the largest worldly owner in the states? State of California. You know, has someone done an economic analysis that says, well, okay, how many tens of millions of dollars of additional revenues would come into the state if we did have that EOR project? And wouldn't it therefore make some sense to say, oh, okay, you put one of those in and no, not only on are we going to give you cost recovery? Hey, here's an extra profit you can make so it will be not only BP and Edison, you'll have two, three, four other people running around because capitalism works and so forth.

So those are some of the business type issues, I think that the group might want to think about. And I guess in my conversation with Commissioner Byron, he asked me if I would, you know, perhaps jot down my notes and send them off to him and so forth and I intend to do that. Thank you.

MR. MYER: Thank you very much. There was a question that came in electronically. That was Will Johnson from Visage Energy. Thank you, Will, and of course we will accept those comments into the record.

Is there any one of the panelists that would like to just comment on this business issue in response to what Will has brought up? Or do we let those stand? No comments. I mean, clearly, the business issue is an important of the overall problem and we will need to take a look at that and will take a look at it, both in the IEPR and the 1925 report. Point well taken.

UNKNOWN SPEAKER: Say it one more time.

MR. MYER: By all means.

MR. JOHNSON: And perhaps I'll share with you, I guess it was mentioned earlier. And when it comes to the renewable portfolio standard and the thought of going from 20 to 33 percent without including CCS, I guess Senator Coleman, before he had all of his political problems and so forth had developed a document that perhaps I'll share with you as well that talks about having a clean energy portfolio standard that would include CCS along with renewable energy.

MR. MYER: Thank you very much, Will. Okay. George. Just identify yourself. Okay.

MR. PERIDAS: George Peridas, NRDC. A question probably for Mary Jane, just for my own benefit. Do we know how emissions from petroleum coke produced at refineries are treated? Because usually the fate or the (indiscernible) has to be exported and combusted using the developing wells. So how is that treated under either the (indiscernible) or AB 32? Is it outside? Or is it considered to displace coal that would have been combusted instead for the production of energy? How does that work? Or is it (indiscernible) part of the California emissions?

MS. COOMBS: Unfortunately I don't know the answer to that, certainly not with the LCFS. But I can find out the answer for you from our LCFS and our reporting folks. And hopefully we can get that posted with the other materials on the website for this meeting.

MR. PERIDAS: Okay. Thank you.

MR. NYER: Any other questions or thoughts? I think we've had a very interesting discussion today. We had some multiple perspectives, particularly on such subjects as liability. So we have certainly work to do there to bring any sort of consensus.

And maybe I'll raise one question for the -- for some comment from some people. In that we started our discussion today with citing a comment about 2020 and whether or not CCS would contribute to that. And, of course, we have the AB 32 framework which says that CCS is primarily a 2050 technology. And we had lots of discussions about, you know, sort of the policy that we needed to do in the interim.

I didn't hear much discussion about the urgency issue here. And whether we can wait until 2020 before we get our act together from a policy perspective or whether we need to do it more quickly being as that's the way the policy has been set out for us.

So I'd like a couple of comments about the -- whether there is urgency or not for us to get some of these policy issues that we have been talking about today resolved and whether we can sort of let it go for another few years, five years, ten years. Or whether we need to -- or what we should be doing with regards to a schedule on this. Anyone want to volunteer? Before I ask. Craig, yes, please.

MR. HART: I think if we wait, we run the -- I don't know where to position myself here. But if we wait, we run the risk of --

MR. MYER: Just -- Craig Hart.

MR. HART: Yeah, Craig Hart, Alston & Bird. We run the risk of projects being delayed and when cap-and-trade or whatever approach is adopted at the federal level takes place, not being prepared at the state level to comply.

Also, I think we should anticipate constraints all along the supply chain for this technology. And certainly, I mean, we're already seeing -- and by supply chain, I mean it broadly -- whether it is building the capture technology or unitizing the land or the policy makers, even, being part of the supply chain as well if you think about it from that perspective.

We had a delegation from China last month that came and it represented everybody from the Chinese -- all the way from the Chinese government, the top of the government, the Ministry of Science and Technology, the people that set policy and decide R&D projects for China, all the way through the equivalent of the DOE partnership heads to the equipment suppliers come for a meeting that was at Harvard. And really it represented the entire supply chain.

And the efforts that they're undertaking in this area are impressive. They're differently focused than ours. Ours are focused more on the injection, some of the technologies for capture, obviously, we have already.

They're focusing more on capture.

But if you think a supply chain approach and you think about how much delay is involved, I think it clearly have to be starting now and we have to scale up because once we need to scale up to the point that we're contemplating, we're going to face tremendous shortages, you know, in the next 10 to 15 year period in this area.

MR. MYER: Geir.

MR. VOLLSAETER: Geir Vollsaeter, Alston & Bird. I worked with the Zurich Emission Technology Platform with the European Commission. We did some work in Europe, what it would take, essentially, to get compliant through bulk reductions in transportation, electricity and a number of other issues. But carbon capture was in.

When you look at the steel needs alone, the pipelines that needs to go in over time to meet the projected products we need and the time it takes to get that deployed, produced and put in the ground, the answer is pretty much given, is that time-wise, you're looking at two to four years, at least, in regulatory work. And another a two to four years, at least, to get hardware in.

Most of the time, for these projects, my experience, my personal experience with this is six years or more. And if you look at the projects that have been in motion for some time, it will take more than eight years to get them set in and that's after working OSPERT regulations, London Convention, different directives and the likes.

And the cost of having an enabling regulatory framework is almost nothing compared to the cost of billing it out. Just enabling the framework is a very low cost initiative.

MR. MYER: Thank you. Any other comments on this?

MR. MHYRE: Rich Mhyre, BKI. I'll echo some of the sentiments and when -- this expression that I've heard a couple of times today is CCS is at 2050 technology, I think we need to just clarify what we mean by that. It's not a commercially ready technology by 2050. It's an already wide-spread commercially deployed technology. And given the need for the learning by doing cycles that Dale discussed and the long lead times on these capital projects to actually get to the point that we would ever have enough systems in place to meet those goals, and most of the mini-analyses for 2050 show CCS as playing a very, very important role, that, in fact, that may sound like a long time off, but in fact, we do now, at least on the technology side, need to be doing the scale-up, doing the testing.

And so, whatever issues need to be worked out in the policy and regulatory and incentive and business and fronts to make that happen, I think there is, indeed, an urgency there and this forum is certainly not unique in stating that need.

MR. MYER: Thank you very much. I have just maybe five minutes. I'm going to ask one other question. We have heard since -- I have been around the block on this issue which has been a while now, the need for outreach, public outreach. And I heard it mentioned today sort of along the same, in the same, along the same lines as, well, we got to do public outreach. Well, we've been doing public outreach.

So I'd like to hear maybe a comment or two about whether we've been doing the right public outreach or whether we need to be doing something more effective because I heard it mentioned today along the lines, well, we got to do public -- we've been doing it. So that means there's a disconnect. Any comments on who we should be doing public outreach to? Whether we're doing it right, whether we're doing it wrong as a community?

MS. RAU: Tiffany Rau, Hydrogen Energy International. Yeah, I think it's a question of kind of magnitude and reaching a widespread public. I think outreach efforts so far have been focused on policy makers and impacted communities as opposed to kind of a widespread. And it's difficult to get to kind of mass public so that CCS, kind of a more common concept, commonly understood technology.

So I mean, I'm getting the point where I think it's media that has to be educated, editorial boards that have to be educated. It's easy to kind of throw up concerns about CO_2 and kind of demonize it when the facts are, for me, the more you learn about it, the more you learn about CO_2 and capture and sequestration, the more it makes sense, the more comfortable you are with it. But when you hear about it for the first time, it's something that makes you take pause.

So, as much as we -- I think the industry and scientists and academia have thus far talked a lot amongst themselves and then have done policy maker outreach. It's time to step up to broader public education.

MR. MYER: Great, thanks. Any other comments? With that, I always like to sort of end on the public outreach notes, kind of a, I don't know, not so technical place to end a discussion.

We have one final -- unless -- now, so I give folks one final opportunity to speak their peace with regards to our Workshop today. Any input? And we had one final agenda item, sort of a formal agenda item specifically for comments from the Department of Conservation or the PUC or CARB. If there is any comments that anyone wanted to officially put into the record from those organizations, this would be the time to do that. And I see none.

And so that makes the last portion of our agenda and our meeting very quick. And if we have no further questions or comments, I want to thank everybody. I think we had a very productive conversation today, provides some much needed and really substantive input for the -- to the IEPR report. Thank you very much.

IN WITNESS WHEREOF, I have hereunto set my hand this 29th day of May, 2009.