COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	Docket No.
Preparation of the 2007 Integrated	)	06-IEP-1O
Energy Policy Report	)	
	)	
Geologic Carbon Sequestration	)	
Strategies	)	
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, OCTOBER 1, 2007

9:05 A.M.

Reported by:
Peter Petty
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

John L. Geesman, Associate Member

James Boyd, Commissioner

STAFF PRESENT

Lorraine White, Program Manager

Kelly Birkinshaw

Jim McKinney

CALIFORNIA DEPARTMENT OF CONSERVATION

Bridgett Luther, Director

Hal Bopp, State Oil and Gas Supervisor

Mike Stettner

ALSO PRESENT

Larry Myer, Technical Director
WESTCARB

Richard Myhre
Bevilacqua Knight, Inc.

Elizabeth Burton
Julio Friedmann
Lawrence Livermore National Laboratory

John Clinkenbeard
California Geological Survey

James Haerter
U.S. Bureau of Land Management

Sarah Wade
AJW, Inc.

ALSO PRESENT

Phillip Price
Lawrence Berkeley National Laboratory

Dale Simbeck (via teleconference)
SFA Pacific

Thomas M. Grieb
Tetra Tech

Michaeleen Mason
Western States Petroleum Association

Bob Lucas
California Council for Environmental and Economic Balance

Mark Nelson
Southern California Edison Company

Tiffany Rau
Hydrogen Energy

George Peridas
Natural Resources Defense Council

James Mosher

I N D E X

P R O C E E D I N G S

9:05 a.m.

PRESIDING MEMBER PFANNENSTIEL: Good morning, we are ready to begin. This is an Energy Commission joint workshop under the Integrated Energy Policy Report Committee. And today we're going to be looking at geologic carbon sequestration strategies based on a staff report on that subject that we have in front of us.

I'm Jackie Pfannenstiel; I'm the Chair of the Energy Commission and the Presiding Commissioner on the Integrated Energy Policy Report Committee. To my right is Commissioner John Geesman, who is the Associate Member of the Committee. To my left is Bridgett Luther, who is the Director of the Office of Conservation, who is joining us. And to the far right down at the end of the podium is Commissioner Jim Boyd. And to Jim's left is --

SUPERVISOR BOPP: Hal Bopp.

PRESIDING MEMBER PFANNENSTIEL: -- from the --

SUPERVISOR BOPP: I'm the State Oil and Gas Supervisor.

PRESIDING MEMBER PFANNENSTIEL: Thank

you.

I think with that, I have no opening comments. Anybody on the podium have comments?

DIRECTOR LUTHER: I was just going to make a few comments because the Department of Conservation, what I like to call the Department of Everything Interesting, also has two very interesting divisions. One is the Division of Oil, Gas, Geothermal Resources, which is headed by the Oil and Gas Supervisor, Hal Bopp. And the other one is the California Geological Survey, which is headed by Dr. John Parrish, the State Geologist.

And those two teams have been working very closely with the Energy Commission. And we've been very excited to be part of this. It's interesting now that we take carbons out of the ground, and then we say, oh, well, in order to keep them from affecting the atmosphere here's an idea, let's put them back in the ground.

So, I'm really pleased with the progress my divisions have been making in working with your teams. I know that they've put a lot of energy into this with all the different stakeholders.

I just wanted to let the group know that

I've just come back from Interstate Oil, Gas and Compact Commission, which is the 30 oil-producing states. I'm the Governor's representative on that. And they have also produced a report on carbon sequestration, which I think together with what's going on with AB-1925, will certainly serve the foundation. And again California's leadership in this role is certainly admirable and should be recognized today.

So I just want to say thanks to everybody that's been working on this. And I particularly want to thank my team, and I know several of them are going to be involved in the reporting today. I look forward to our future partnership. Thank you, Jackie.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Bridgett. Yes, Jim.

COMMISSIONER BOYD: I just want to make a comment that even though to many of us this is a deeply technical subject that we've been following for a long time, and as our Chairman knows, carbon sequestration is talked about always in the context of climate change.

But this is a highly political subject, as well, because as I think most people up here know, all discussions of climate change activities in this country, all discussions relative to the use of coal in this country for generating electricity, and particularly in the western states where the Western Governors Association is much involved, because they are coal states, the subject of either coal-to-electricity or coal-to-liquid transportation fuel, which is a raging debate within the Western Governors Association working group on transportation fuels now, everybody ties everything to solving the carbon problem with carbon sequestration.

And yet, as we debate the science and technology here, we know a lot of additional work needs to be done.

So while many people in many places say, well, carbon sequestration, that's the answer to the problem, many of you, many of the staff, many of us continue to work to advance this along.

I see this work that these joint staffs have done as filling a very important role in the continuing discussion and debate about climate change and solutions thereto.

So I look forward to the outcome. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Jim. Turn it over to Lorraine.

MS. WHITE: Good morning and thank you. Welcome everyone to one of the Integrated Energy Policy Report workshops. Today we're exploring, as the Chairman has said, the issue of geologic carbon sequestration and the strategies that have been identified in the staff's report.

This particular report was directed to the Commission as a result of Assembly Bill 1925, to be included in the 2007 Integrated Energy Policy Report. And today we're hoping to explore people's comments and issues related to the staff report that was issued. And perhaps find out exactly how best to refine the report.

(Pause.)

MS. WHITE: Before we begin there's always a few logistical things we have to cover, especially for those of you who have not joined us before, this will be new information. And for those of you who have, I ask you to be patient.

We have facilities, restrooms are just out the door and to the left, also behind the elevators. We have a snack shop on the second floor in case anyone wants refreshments.

And in the event of an emergency and the sounding of alarm, we ask that everyone please follow staff out the building and convene across the street at the park, Roosevelt Park. Wait there until we have the high sign to return.

In terms of our participation today, we are using the WebEx function; it allows us to have a much better interaction with participants who actually can't be here. We also have a view-only, audio-only service through our webcast.

The notice provided a call-in number, and the meeting information which you would have to put in when you go to our website and select the WebEx feature.

One of the particular things that allows this meeting function to be most helpful is the raise-hand button. When you have a question or a comment about information being presented, we have a staff person here who then is alerted to that. And we can call you in order.

The way we actually are going about having participants with us go through the discussions, we will be asking those at the dais if you have comments or questions, those in person to come and ask questions. There is a microphone there that is on, so it will be able to pick up your voices nicely. And then use the WebEx function. And lastly, those who are calling in on the phone only.

Today's agenda is pretty straightforward. We want to provide you with an overview of the carbon sequestration activities that are currently going on, an overview of our staff report, as required by AB-1925. And then this afternoon we're going to be going through a panel discussion about carbon sequestration. And then, of course, the public comment and question period.

The Energy Commission, every two years, is required to assess and forecast energy supplies, demand and price. Related to that we investigate specific special topics. Some of them are required, as a result of legislation such as what we're discussing today. But then also as part of our analysis we identify issues that require further investigation.

The staff report, Geologic Carbon Sequestration Strategies for California, is available on our web. Unfortunately, we were not able to get copies here this -- we'll have some later today, but they're not there yet.

And it is from this work, all of the staff's analysis, including the work here on carbon sequestration, that the Commission then develops and recommends energy-related policies that help to address these issues.

It is important that we get your participation to help us refine the analysis that we conduct. And also to refine the policies we recommend.

As is demonstrated here today, we work closely with various agencies to insure that we reflect the particular issues that they have to address, and partner with them to have a more robust analyses.

To date, as part of the 2007 proceeding, we have conducted 43 public workshops. Today is our 44th. As a result of all of this discussion and participation we've explored at least 20 different issues. And we'll be addressing a wide range of those issues as part of the Committee's report, which we hope to get out this week.

The final report will be adopted on November 21st. And then shortly thereafter transmitted to the Governor and the Legislature.

As part of this proceeding, in this particular topic, this project, we had asked that comments be provided by October 5th on the staff report. This will allow us then to address these comments and about mid- to late-October, publish the final staff report.

And we are seeking to adopt the report, depending upon the nature and extent of the comments, either on October 24th, that's assuming everybody loves it. And if we need a little bit more work on it, November 7th.

We make this proceeding as transparent as possible. Our analyses, our reports, our notices, all of the information related to the workshops is available on the Commission's website.

For those of you that have general questions about the proceeding, itself, or the overall scope of the work that we're engaged in, you can contact me. If you have specific questions about geologic sequestration, that I ask for you to direct your comments to Kelly Birkinshaw, who I'll be introducing shortly; or Elizabeth Burton. The information for all of us is available in the notice associated with today's workshop.

If there are any questions I'd be happy to answer them. Otherwise, I'd like to introduce Kelly.

MR. BIRKINSHAW: Well, I guess while my presentation is coming up for the record I'll introduce myself more specifically. My name is Kelly Birkinshaw. I manage environmental research for the California Energy Commission, of which generally climate change, and in particular technology development on carbon sequestration, are major components.

As Lorraine mentioned, what we're here to talk about today is a --

PRESIDING MEMBER PFANNENSTIEL: Excuse me, Kelly, you might want to dim the lights.

(Pause.)

MR. BIRKINSHAW: Okay, now perhaps we're ready. As I started to say, we're here to talk about a report that was mandated by legislation, Assembly Bill 1925, by Assemblyman Sam Blakeslee. This is a report that passed in August of 2006, and directs the Energy Commission to work with the Department of Conservation to develop a report for recommendations of how the state can accelerate the adoption of cost effective carbon sequestration.

The report, itself, or -- excuse me, the legislation, itself, also mandates further research and development on this topic. And directly links the report to the 2007 Integrated Energy Policy Report, again as Lorraine mentioned a few minutes ago.

What I'm going to do this morning is provide just some general background and context for geologic carbon sequestration, and hopefully set the stage for the more detailed presentations that occur later this morning, and the panel discussion that we have this afternoon.

So, I'm going to try to just hit the very high points of the technology, itself, as well as the process we use in developing this report, and some of the high-level findings in the draft report, itself.

This cartoon depicts the general components of a geologic sequestration system. In essence, what we're talking about is capturing carbon dioxide as a result of industrial processes. And more generally, the combustion of fossil fuels. That CO2 is removed from flue gases from combustion; it is cleaned and compressed; and then compressed to a point of a supercritical stage. Which simply means it's cooled to a point that it has liquid-like properties so that it can be stored in large volumes at an appropriate site.

In the volumes we're talking about here, the CO_2 would likely be piped to an appropriate geologic site; and then injected into the subsurface for storage in geologic timeframes. That is hundreds of thousands of years.

This shows a cartoon of how a carbon sequestration industry might operate here in California. Again, we're talking about capturing CO_2 from large point sources and piping -- or transporting that CO_2 via pipeline to appropriate sites where it can be injected into the subsurface.

It's very analogous to other industrial processes such as natural gas. As you're all aware, natural gas also is transported via pipeline. Pipelines, in fact, criss-cross much of California.

Our utility companies also store natural gas underground, as well. So these are processes that are relatively well understood and have been practiced for many years.

CO2, itself, is captured from natural formations in the western United States and transported by pipeline to oil fields in Texas for enhanced oil recovery.

I like to put this slide up because I think it provides some context for the importance of geologic sequestration really on both a regional and world scale. This graph was produced by Pacific Northwest National Laboratories, and it's based on some analysis done by the Intergovernmental Panel on Climate Change.

What it shows is a graph, the top line of which is the business-as-usual case of the emissions worldwide. They did some analysis to determine if there was a concerted effort to adopt advanced energy technology, and then produced the middle line, which is a basecase.

The bottom line is the emissions profile that we have to get to if we're going to stabilize CO2 emissions in the atmosphere, and therefore mitigate the effects of global warming.

I think one of the things that jumps out immediately, even with some fairly aggressive assumptions, there's still a fairly significant gap. And that gap needs to be filled if we're going to get to a profile that stabilizes those emissions.

Just to give you some feel for the assumptions that were built into the basecase, it assumes that 75 percent of all electricity production worldwide is from nonfossil fuel sources by 2100. And presumes that by 2050 energy efficiency will have increased by 45 percent in all regions and all sectors of the world.

So, these are fairly monumental tasks before us. And as a result it's clear there really are no silver bullets. We need to approach CO2 or greenhouse gas reductions from multiple angles to develop a comprehensive carbon management strategy. And carbon sequestration becomes one of those strategies to consider, along with other opportunities such as further energy efficiency, and renewable energy, as well.

Just to put this into context of recent legislation here in California, AB-32, of course, establishes emissions reductions, a goal of in fact 1990 levels of greenhouse gases by 2020. Generally speaking, geologic carbon sequestration is not considered one of the major technologies or strategies that could help to achieve that AB-32 goal.

That being said, I think it's also important to note that there are commercial projects under development even today. Most notably the project at Carson to use petroleum coke by British Petroleum. In that case the project would produce electricity and use the CO2 for enhanced oil recovery in oilfields nearby.

SB-1368 establishes an emission standard for CO2 for all long-term power purchases for electricity coming into California. I think it's important to note that geologic sequestration is probably the only technology we know of now that would allow for use of a relatively abundant and generally low-priced fuel, such as petroleum and coal, were we to use those for electricity coming into California.

Governor Schwarzeneggar has also established some fairly specific policy in this arena by executive order. I'd like to note that in his executive order of June of 2005 he established a goal for 2050. In that goal he calls for an 80 percent of greenhouse gases below 1990 levels.

And most analysts suggest that these are the kinds of goals one needs to achieve if we're going to ultimately stabilize CO2 emissions. And not just on a regional scale, but, of course, on a worldwide scale. Again, as a way of mitigating the effects of global warming.

The primary goal of AB-1920 was to assess the technical readiness of geologic carbon sequestration, so it was a very technical assessment of the methods used to capture the CO2; ways in which we go about characterizing sites, as well as monitoring, and if necessary, remediation.

But it was also an assessment of barriers and uncertainties relative to developing ultimately a carbon sequestration market here in California.

In this report we developed a number of recommendations, some of which we think is oriented in a more technical way to continue with developing technology. But I think it's also clear that we're at a point where these various initiatives can occur in parallel.

That is to say while R&D continues, it is probably appropriate to start doing more detailed evaluations and addressing these issues in the regulatory and statutory arena if we're ever to get to a viable market.

Given the uncertainty that we did observe the analysis, we intend to continue to examine these issues and anticipate a revision to the report based upon data that would come from pilot-scale demonstrations of this technology, that I'll talk about in a few minutes, in the 2009 and 2010 timeframe.

These are the specific topics that AB-1925 mandated that we examine in coming up with our assessment of this geologic carbon sequestration. The report, itself, is organized along these same topics, in chapters. We'll be dealing with them all specifically later this morning and this afternoon. So, for expediency, I'm not going to go over them in any detail here.

But we did do a very detailed examination of each one of these topics for the report.

I have to acknowledge the role of WESTCARB, the Western Regional Carbon Sequestration Partnership, in providing a foundation for our analysis in this report to the Legislature. Particularly the work that was done early on, assessing broadly the technical potential of carbon sequestration in the western United States. This is work that was primarily accomplished through staff, staff assistance at the Department of Conservation, particularly in the geologic survey.

We had completed this broad assessment, although I have to say it is a first-cut assessment of the technical potential. And they're now in the midst of developing some small-scale, that is pilot-scale, demonstrations of geologic carbon sequestration, one in Arizona and the other here in northern California.

In those cases we'll be putting in a relatively small amount of CO_2, something on the order of 2000 tons, which is a small amount, but will allow us to validate the techniques for predicting and monitoring the ultimate fate of the CO_2 in the subsurface.

We also have plans in the works for a large, commercial-scale demonstration of this technology in southern California, outside of Bakersfield. In that case, if we are successful we will do a demonstration at about a million tons of CO_2 over a four-year timeframe.

I have to also acknowledge the

assistance that was provided by other state agencies in helping to pull this report together. There are a number of interesting dimensions to developing a carbon sequestration market in California. These various agencies provided substantial assistance to us. As well as broad stakeholder participation, particularly from stakeholders representing industry, as well as the environmental community.

The primary approach that we used, however, in putting this together, was to retain experts really of national caliber to do whitepapers on the topics identified in the legislation. And our role here was to then integrate those whitepapers into a single report that is appropriate for decisionmakers and submittal to the Legislature.

Just to give you some feel for the magnitude of the potential here in California, again based on WESTCARB's analysis we were able to identify two major categories of geologic formations that seem appropriate for developing this sequestration. Oil and gas fields, particularly depleted fields are an early obvious candidate for this technology.

On the left map, it's kind of hard to see, but those purple dots all indicate oil and gas fields here in California.

The much bigger potential, however, is in saline formations. And it turns out that many parts of California have the right geology for this. The yellow highlighting in the right-hand side of the map shows where saline formations occur. And as you can see, much of the central valley where we see much growth recently, and is projected for the future, is a first-level candidate for development of projects.

This map shows the relative proximity of the major large point sources of CO2 and the sinks, that is the places where there are oil and gas fields, or saline formations. And as you can see, there's a good alignment between where the sources are located, as well as the sinks.

To give you again some sense of magnitude, transportation, which is the largest source of CO2 in California, comes in about 180- to 190-million metric tons per year. Just looking at instate natural gas power plants, oil refineries and cement plants, we're looking at a total of about 42 million metric tons.

If we were to add out-of-state, coal-fired power plants that primarily supply electricity to California, we're coming in at about 100 million metric tons per year. So these are a very large target in a comprehensive carbon management strategy.

ASSOCIATE MEMBER GEESMAN: I don't understand your point, though, about close proximity between sources and sinks. It would seem to me that your mention of out-of-state coal plants, which presumably are as carbon-rich a feedstock as we're going to find, are nowhere close to the sinks that you're looking at.

MR. BIRKINSHAW: Right. Well, you know, the WESTCARB program examined the western United States. And it turns out that while California has a particularly rich resource for this technology, it's also available in neighboring states, as well.

So there's reasonable alignment even in the coal-fired power plants in adjacent states and large sinks in terms of the geologic formations.

ASSOCIATE MEMBER GEESMAN: So that conclusion is a regional conclusion, it's not a California-specific conclusion?

MR. BIRKINSHAW: I tried to do both, actually. If one just simply looks at California, there's roughly, you know, 42 million metric tons per year that become targets for sequestration, and for, you know, carbon management.

ASSOCIATE MEMBER GEESMAN: But pretty heavily dispersed tons, aren't they?

MR. BIRKINSHAW: They are actually identified on the map on the left-hand side of this cartoon. You'll see the triangles, dots and squares locate the large point sources that we were able to identify in the phase one WESTCARB program.

ASSOCIATE MEMBER GEESMAN: Well, the size of my map is such that I'm afraid it's more blur than triangles, dots and squares.

MR. BIRKINSHAW: I apologize for that. I guess I'll just have to say that I can get you more detailed information. But one of the things that we did do was to locate these large sources and map them onto the locations for appropriate geology.

ASSOCIATE MEMBER GEESMAN: So, would a refinery be considered a point source or a collection of hundreds, if not thousands, of point sources?

MR. BIRKINSHAW: I think that depends on who you talk to. It is certainly true that a refinery produces literally hundreds of sources onsite. But if one looks collectively at those sources, on a footprint of the refinery, they'd become a single, large source of CO2.

ASSOCIATE MEMBER GEESMAN: But if I had the belief or concern that the most economic applications would probably be pursued first, how would a refinery rank compared to a coal plant?

MR. BIRKINSHAW: A coal plant, I would say, is the preferred alternative. Certainly because of the higher concentrations of Co2; and it is a stand-alone facility. No question.

MR. SPEAKER: You may want to distinguish between (inaudible) --

MR. MYHRE: Excuse me, Commissioner. I'm Rich Myhre --

ASSOCIATE MEMBER GEESMAN: You need to come to the microphone, Rich.

PRESIDING MEMBER PFANNENSTIEL: You need to speak into a microphone.

MR. MYHRE: Excuse me, Commissioner. I'm Rich Myhre; I'm part of the WESTCARB team.

I'm more of a sort of designated generalist on the project, but I am familiar with this information.

Some refineries contain hydrogen plants. In making gasoline you have to have extra hydrogen. And there is sort of an older type of hydrogen plant that many refineries in the state have. And that plant produces a relatively pure CO_2 stream.

You'll hear later that there are basically the low-hanging fruit, if you will, are a variety of industrial processes that produce naturally a relatively pure stream of CO_2. Therefore, the capture cost, which is typically a big component of the overall cost of sequestration, is low.

So, what they would call a Benfield type, or older type hydrogen plant in a refinery fits that category. Ethanol plants fit that category. The state is considering biofuels programs that might expand a number of ethanols plants. There will be a great opportunity to couple those with capture and sequestration.

And I think what this map is trying to show is if you, for example, look at those ethanol plants and where might they be sited, most often it would be the central valley.

It is easiest for sequestration if you just can inject straight down as opposed to having to build a pipeline somewhere.

So, I think the point of this map is in sort of helping to identify the instate low-hanging fruit.

I think that when you look at the magnitude of capture and storage that might need to be applied to get to the 80 percent reduction that we're looking at in 2050, or even other intermediate goals, you will probably be looking at a combination of capture applied to instate sources, particularly those low-hanging fruit ones and the coal plants in the states in the intermountain west serving California loads.

Thank you.

MR. BIRKINSHAW: Okay. The next couple of slides just simply highlight, at a very high level, the findings from the report. I think, you know, one of the clear conclusions is there are important gaps in both statutory and regulatory frameworks. And, in fact, these gaps may very well ultimately be show-stoppers unless they can be dealt with efficiently.

This is particularly true in dealing with a long-term liability of CO_2 carbon sequestration.

We believe there is a clear need for continued research and development to develop the techniques for monitoring and validation of CO_2 migration. And, in particular, CO_2 capture technology.

As Rich Myhre mentioned, CO_2 capture is the single largest cost in developing projects for carbon sequestration. It represents something on the order of 80 percent of the overall costs of a project. And so that becomes a clear target for further research and development.

We know a considerable amount of information about the geology in oil and gas fields, simply because of the large exploration that has occurred in those areas. Relatively speaking, though, we know very little about these deep saline formations, simply because there hasn't been very much exploration.

The first level assessment that have been done suggest these are very good targets, but it's also clear that much more detailed characterization needs to be done in order to identify sites that are appropriate for this technology.

Because of the fact that CO_2 has been used effectively in enhanced oil recovery that becomes an obvious candidate for carbon sequestration. I think one of the clear messages that we heard in this assessment, however, is that we need to do much more detailed evaluations of the operational infrastructure and regulatory implications of linking enhanced oil recovery and sequestration.

And in that vein I think, you know, one of the strong messages that came through as well is that there needs to be continuity and flexibility in the regulatory frameworks that are developed to support this technology; to streamline, if you will, the projects, while, of course, protecting public health and safety.

And lastly, there's a clear need for continuing education and outreach to better define both the impacts, as well as the benefits that might accrue to local communities where these projects might be developed.

We think the report, itself, is important for staff. Again, we've identified areas for further research, as well as, I think, the starting points for more detailed regulatory and statutory debate about its role, and the best way to implement it here in California.

And, in fact, some of this may have to occur alongside the development of more demonstration projects that are in the works in other parts of California.

Just to give you a sense of where we are in the schedule, again today's workshop is to present the contents of the report and to receive public comments. I'm anticipating that we will consider this report as part of a Commission business meeting on October the 24th. And we hope to submit the report to the Legislature on time on November the 1st of this year.

That really concludes my overview presentation. During the course of the balance of the day we'd like to, following my presentation, review activities that are going on worldwide on how they feed into development of a knowledge base and complement other research that's going on, specifically here in the state.

Following that we will then have a presentation that goes into considerably more detail about the content and findings of the report, itself. And then we have, as Lorraine mentioned, again a panel discussion with the authors that were key to the whitepapers that are foundational to this report available for a panel discussion this afternoon.

And then following that we will have an opportunity for comments and questions from the stakeholders and the public.

That really concludes my presentation. I'd be happy to answer any questions.

PRESIDING MEMBER PFANNENSTIEL: Any questions from the dais? Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: What's the injection process comprised of?

MR. BIRKINSHAW: The injection process? Well, others, I think, are probably later in the day are better able to answer the questions. But as I understand it, it's really a matter of drilling a well, lining it appropriately, and then pumping high-pressure CO2 into a formation.

Okay. Our next speaker is Dr. Larry Myer. He is the Technical Director for WESTCARB.

DR. MYER: Thank you very much, Kelly; and thank you very much, Commissioners, for the opportunity to address you today.

You're going to hear a lot of detailed discussions this afternoon of what we know and what we don't know about geologic sequestration. So we thought it would be a good thing to provide a little bit more overview information and some fundamentals about sequestration; to provide a little more context for the detailed information that you'll be hearing in the afternoon. The purpose is to get some of the issues out on the table in sort of a compact form, and further context for this afternoon's discussion.

I'd like to begin with a schematic representation of the storage of CO_2 in the subsurface. And these are rather cartoonish types of depictions of the subsurface, and in particular, the vertical scale is not accurate. We actually will be storing CO_2 at depths of perhaps 3000 feet or greater.

But I show these to represent the kinds of geologic structures which are ideal for storage of CO_2. CO_2 is stored in the subsurface by a combination of physical and chemical processes.

One has to recognize that CO_2 in most cases, not all cases, but in most cases, is more buoyant than the fluids that are in the subsurface. And so, a fundamental important aspect of the subsurface is geologic structures which would trap this buoyant fluid in the subsurface.

And the one on the bottom right corner I want to highlight a little bit, because in California we have many many representations similar to this. This shows a faulted media in which the CO2 is pumped into a reservoir of rock which is actually adjacent to a fault. And that fault, itself, provides the seal for the CO2. The fault prevents the CO2 from rising up through the subsurface.

And so there's lots of discussions about faults, whether they're good or whether they're bad. But we know from the geologic perspective that faults can provide effective seals for CO2. One of the major things that we address in site characterization is determining whether faults are good seals or not seals in the subsurface.

This overview of the world is intended to demonstrate that there is quite a lot of activity going on throughout the world with regard to CO2 injection and storage activities.

So the concept of injection of CO_2 in the subsurface is not a unique, new concept. There is, in fact, considerable industrial experience around the world with regard to injection of CO_2. Albeit, and this is important, not for purposeful sequestration, however.

But nonetheless, all of this does provide an important knowledge base that we can build on for doing purposeful sequestration.

I now turn to an important report done by the IPCC, the Intergovernmental Panel on Climate Change. Over 124 scientists worked together to produce this report on carbon dioxide capture and storage. And this is very important to highlight because it represents basically an international consensus on geologic sequestration issues.

I think the bottomline from the report is that there's no fatal flaws in the concept of doing geologic sequestration. It certainly does not address the issues that still have to be resolved and worked on at the regional and local issue.

But you can see the variety of topics that they address; the availability of sinks; the technology readiness; costs; risks; monitoring and remediation, all of the central issues associated with sequestration.

I'm now going to talk to a couple of these particular things. And clearly, the risks of doing geologic storage is a topic of concern. And there's been extensive work to study the risks associated with geologic storage. And I've listed a number of the impacts, risks associated with that.

The impacts of unintended leakage; health and safety of workers and the general population; environmental impacts; unwanted intrusion into drinking water, meaning we don't want the CO2 to go into the drinking water supply.

Over-pressurization, in fact, can result in seismic activity. Unwanted intrusion of saline fluids means if you're pumping large quantities of CO2 into saline formations, one must be aware that the saline fluids will move; and you don't want them going where you don't want them to go.

But now I have a quote on the right from the IPCC study, which is worth reading. It says: With appropriate site selection, informed by available subsurface information, a monitoring program to detect problems, a regulatory system and the appropriate use of remediation methods to stop or control CO2 releases if they arise, the local health, safety and environmental risks of geologic storage would be comparable to risks of current activities such as natural gas storage, EOR and deep underground disposal of acid gas.

In summary, I think to paraphrase, again, it says that the risks of doing geologic sequestration are comparable to many of those industrial processes that we carry on today. But it highlights the fact, of course, that we need to do it right. We need to have monitoring program and a regulatory system in place to do it properly.

ASSOCIATE MEMBER GEESMAN: Larry, let me ask you, I'm not certain that that's -- the IPCC statement is exactly parallel. They speak to the local health, safety and environment risks being the same.

It would occur to me that if, in fact, society embarks on an effort to store CO2, that there may be a demand or expectation that the retention quality of our storage systems be higher than simply those which, in these other contexts, would present a health, safety or environmental risk.

And I wondered your reaction to that.

DR. MYER: It is certainly true that geologic sequestration, to be of any benefit, has to retain the CO_2 in the subsurface in sufficient quantities that you don't lose the game of keeping the CO_2 quantities in the atmosphere low enough.

ASSOCIATE MEMBER GEESMAN: Have these other industries or other applications of storage technology have that same level of let's say low tolerance for leakages?

DR. MYER: The important point here is that the health, the local impacts are, and were considered, in fact, by the IPCC community, to be a higher, more prominent issue.

The potential for keeping the -- and the risks associated with keeping sufficient quantities of CO_2 in the subsurface to mitigate climate change are really very very small. It does not seem to be much of an issue with regard to geologic sequestration.

The capability of the subsurface to store these fluids in sufficient quantities, such that we're going to mitigate climate change, is well demonstrated. The risks that need to be discussed more extensively are the local risks associated with what's going to happen, how likely would it be to happen, that we have a well blow out, which is a local phenomena, would we have the possibility of CO_2 leaking to the surface and causing some tree killer, an environmental effect.

So this was the -- the reason that we -- this is stated in this way is because of the focus and interest on the local environmental effect, and the level of confidence in the subsurface, maintaining the fluids to -- for mitigation of the climate event.

Another key element that's often talked about is will we be able to appropriately monitor the sequestration projects. And there is a sophisticated geophysical technology directly applicable to geologic sequestration, which has been developed in the oil and gas industry. So there is a large knowledge base available for doing this very important task of monitoring.

There is no doubt, however, that additional approaches should and are being developed.

An assessment of the cost of monitoring

over the operational life of a project is on the order to 10, 20 cent a ton for CO2. So, from the perspective of cost, monitoring does not appear to be a major source of concern for geologic storage.

Having said that we have all these sophisticated technologies, we need to evaluate, on a regional and local basis, which of these technologies will work appropriately for the particular geologic environments in which we are working.

And that's a point that I'll return to later; and it's a point that we will be dealing with this afternoon.

The graphic on the right is simply a picture of one of the major success stories in the world, which is use of 3-D seismic to monitor the plume of carbon dioxide injected at the Sleipner project in the North Sea. And the pictures on the lower part of the right, the colored pictures, basically are an interpretation of the seismic results which show the location of the plume.

And I show this particular picture because seismic technologies are probably the best applicable technology with the highest resolution for monitoring CO2 plumes. So there's a natural focus on the use of seismic technology and evaluation of how well it will work, in particular, in geologic environments that we have to work with.

Here's a picture of the west now; we've taken a step back to look at the saline formations in the western United States. And the point I wanted to show here, the blue globs here are the saline formations throughout the western states. And this information comes from the Department of Energy NAFCAR source, which is compiling the information provided by the various regional partnerships.

The point I wanted to make with this is that there are lots of locations, particular saline formations which have very large capacity. And they are distributed in many places, but they are not uniformly distributed. So one does have to consider that you cannot arbitrarily put a pin on the map and find a good sequestration site.

If you look at the map the places where we have good -- and the best opportunities are where you see the largest blue globs. Places which we have lesser early opportunities are also seen here clearly. For example, Nevada.

Portions, in fact, of southeastern California and southern Arizona.

Having said this, --

COMMISSIONER BOYD: Larry.

DR. MYER: Yes.

COMMISSIONER BOYD: Do I infer from your map that a lot of these coal-fired power plants in Wyoming and Montana we worry about are sitting above seas of saline water aquifers?

DR. MYER: That is correct.

Some of the best early opportunities may be in California. And why are these best early opportunities? We have a large amount of data already available to characterize these reservoirs in particular. And we also, of course, as Kelly just mentioned, have oil and gas fields associated with those same saline formations.

So this slide is courtesy of Schlumberget. And it shows a proposed framework for commercial projects. And I wanted to show this slide for two reasons. First of all, it represents a major international corporation who has decided that geologic storage is a business opportunity. So that's an important step. It means that we have a major international corporation deciding one can pursue sequestration as a commercial business.

Secondly, it shows the scope and detailed information that needs to be acquired in order to carry out a project. It gives some sense of the timeline. It will be perhaps three years, if you're looking at a site which has not had previous subsurface development occur, in order to gather the information that's required to get the site to a position where you could begin, in fact, the final design and construction of a sequestration project.

So it's important to note that the sequestration projects are not small undertakings. They are significant industrial undertakings. And, in fact, I think we need to recognize that regulations need to be in place so that the due diligence associated with an undertaking like this actually occurs.

The final point that I really want to talk to is the need for doing local pilot tests, field tests, in locations where we think we could do geologic storage.

In general, field tests provide the regional knowledge that's essential for implementation of this technology. What does that mean? It means that we are in the field testing the specific technologies that we think are best for the locale in which we're working. They could be enhanced oil recovery, enhanced gas recovery or saline formation storage.

It allows us to assess the capacity of these formations; better define costs; assess the leakage at the particular locations; gauge the public acceptance; exercise the regulatory requirements; and validation of monitoring methods.

In the United States the principal publicly funded program gathering such information is the U.S. Regional Partnership Program. And Kelly had already mentioned WESTCARB is one of these regional partnerships. And it's being conducted in a phased process, with the second phase, which is now underway, focused on the pilot studies; and the third phase which is coming, the large volume field tests, which are necessary in order to collect the information that I just alluded to.

The WESTCARB field tests are going to be conducted in the central valley. Why are we going to conduct them in central valley? Because the central valley is that great big green glob in the center of California which, as Kelly just said, represents the most significant potential storage capacity for the state.

And so we've sited our pilot tests specifically to test the subsurface in the sedimentary basin which has the largest storage potential for the state.

The phase two pilot that we're planning is in the southern Sacramento basin. And so that, roughly on your picture there, is where you see all of the little red dots associated with the gas fields in the central valley.

And, in fact, it targets formations which have gas in them. And one of the tests we want to do is to look at the potential for enhanced gas recovery.

Our phase three, or large volume test, is going to be located in the southern San Joaquin Basin, just outside of Bakersfield. Once again, this large volume test being an opportunity to inject a million tons of CO2 in the subsurface.

We've already learned, I think, sufficient significant lessons based on the pilot studies that we're beginning to undertake. Certainly what we learned is going to help in establishing the regulatory and legal frameworks, just because we've had to run through the process for even these small pilots.

And the picture here is a schematic representation of our northern California pilot in which we want to inject CO2 into two locations in the subsurface, one of which was a depleted gas zone, and one of which is a saline zone.

And we, as a result of this, when we worked through regulatory issues associated with this, we found that the state would, in fact, permit the short-term injectivities test, the injection into the gas zone while the USEPA would regulate the injection into the saline formation.

Similarly we are working through issues associated with minerals rights and land access agreements. All of these providing an important experience for the projects that come next.

Now I want to turn a little bit to the question of why we need to do pilot tests locally. And the first point with regards to this is that regional geologic settings vary. And I have here shown on the top a regional cross-section through the southern San Joaquin Valley. And on the bottom, a regional cross-section through the Colorado Plateau.

And they're basically at the same scale. And they certainly show that the level of complexity in the California sediments is quite different from that in Arizona.

What is not seen here is probably one of the most important issues with regard to doing sequestration in California, and the reason we had to do these local tests, is at a scale, smaller scale yet, than what you see here, is the issue of compartmentalization in California.

I had already mentioned very often in California we have these faults which provide the traps for the fluids. But there's a high degree of compartmentalization in the sediments in California. And these raise issues with regard to what monitoring will work best, how we characterize, how we develop the fields. And it is important that we look at these systems specifically and get the knowledge from those.

ASSOCIATE MEMBER GEESMAN: Does that reduce your ability to generalize from the results?

DR. MYER: The generalization, if you -- the way in which we can generalize from the results is we can generalize to other similar geologic studies. And we have, we have many levels here. There is knowledge which is gained from, for example, the tests that are going on in North Sea, which is relevant.

But specific questions about particular issues associated with geology, we have to go to the particular geologic setting and do those tests.

ASSOCIATE MEMBER GEESMAN: But as a consequence is this research more promising in geologic settings which may be more fungible with other geologic settings than one which is the subject to site-specific characterization, as the San Joaquin Valley?

DR. MYER: Well, one would hope that you could do these tests in as fungible a geologic setting as possible, that's true. Which is another reason in California for the central valley. The central valley has characteristics which are similar to many of the other bases in California. And so from that extent it is fungible to other basins.

And, in fact, though I'm not an expert in this, other geologic settings, even on the Gulf Coast of Texas, the information, to the extent that the depositional environments are similar, is always transferrable.

I have just two other examples of issues that we need to address on a regional basis; the answers of which help us and better define the types of regulations that we need for particular areas in which we're located.

And the question is what is the storage capacity of potential projects in the central valley. We have done an assessment at sort of a crude level, if you will, of the general capacity of the central valley. But the capacity associated with a particular project will most likely be very much different than the general number that would provide for the entire basin.

And this is important. It directly relates to the project design. We need to know, per unit, per cubic meter, how much CO_2 we're going to be able to store in the subsurface in order to get a handle on the size of the subsurface real estate that's going to be associated with the project.

And there are many factors which affect the particular amount of CO_2 that would be -- could be stored at any location, including the particular two-phase flow properties of the media; the hydrogeneity compartmentalization, all of these things which make it very difficult to predict in a generalized fashion what the specific storage is going to be at a particular location. This is the kind of information that you can get to when you start doing the field tests.

And then finally a comment on seismic methodologies, because seismic, as I mentioned, is such an important potential technology for monitoring. The question is, will it work everywhere. And the answer is no.

But it will work in many places, and we need to define better the conditions under which it will work. And this is important when we're thinking about the regulatory -- the details of the regulatory -- regulations that we put in place. How specific do we want to be about the monitoring technologies that we will use.

The graphic on the right is a more detailed, technical graph than you would ever, I'm sure, want to see. But what it says is that when your reflectivity of a layer containing CO_2 in the subsurface will be a function of whether the rock is consolidated or unconsolidated. That means indurated or not.

And you can see those sets of curves look quite different. So that's just one factor that needs to be taken into consideration and reflectivity means how well the seismic energy is reflected from the layer. And that is the information which is used to develop these seismic images.

So, structural complexity, rock properties, methodologies, surface conditions, presence of gas, many things affect seismic response. Once again, making it difficult to predict in the abstract or in generalities about what's going to work and what's not going to work.

So, once again, uncertainty in these predictions are decreased by field tests. The necessity for doing pilot studies of all scales.

SUPERVISOR BOPP: Larry.

DR. MYER: Yes.

SUPERVISOR BOPP: When you're talking about conducting monitoring for a carbon storage project, do you anticipate that regardless you'd use a variety of monitoring techniques? I mean you've got seismic, you've got monitoring wells, leak detection. How do you see that?

DR. MYER: I anticipate a portfolio of techniques being applied for monitoring. And for one reason it is because no particular technique will work everyplace under every condition. And so we have to take a portfolio approach.

We have to design monitoring systems on a site-specific case. And I highlight seismic because it is one of the few methods which enables us to look in between wells and for a considerable distance aerially outside of the wells.

And so while we will have a portfolio of techniques available, seismic is certainly an important one for establishing where the plume in in an aerial perspective.

So, I'd like to end that just with general summary comments. That there's a general consensus in the scientific community of the technical viability of geologic storage. A large amount of technical expertise already exists. But the field tests provide information essential for answering remaining questions specific to implementation in California.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Larry. I think now we have a panel. Are there other questions?

(Pause.)

MR. BIRKINSHAW: I'd like to introduce now Elizabeth Burton, who is from Lawrence Livermore National Laboratory. She's a staff scientist at Lawrence Livermore. She's the principal author for the AB-1925 report, and will now present a summary of the report.

(Pause.)

MS. BURTON: Thank you to the Energy Commission, as a whole, for giving me the opportunity to work on this report. And I want to make the point right up front that I am either the top of the pyramid or the tip of the iceberg, depending how you view this topic.

But our working group, myself, Kelly Birkinshaw, Larry and Rich Myhre, I think you've heard from all of them already this morning. And in addition, over at the Department of Conservation, Cameron Downey and John Clinkenbeard, Bill Winkler and Mike Stettner were very helpful and instrumental in helping us put the report together.

And all of our whitepaper authors, I think, deserve mention. And I don't want to make this sound like the Academy Awards, but their names do need to be, I think, mentioned.

Sarah Wade worked on the regulatory chapter; Phillip Price, Tom McKone and Michael Sohn worked on the risk aspects; Vello Kyuskraa worked on remediation and mitigation; Howard Herzog and James Katzer worked on the economic piece; Sally Benson and Larry Myer contributed the monitoring and verification foundational chapter; Julio Friedmann, the site characterization piece; Dale Simbeck, the capture technologies piece; and again, John Clinkenbeard and Cameron Downey were instrumental in providing kind of an update to the geological potential issues as a followup to the WESTCARB study earlier.

ASSOCIATE MEMBER GEESMAN: Are the whitepapers available to the public?

MS. BURTON: The whitepapers will be published as a PIER report. Given the fast-track nature of this, we kind of got so involved in trying to get the report ready that getting the PIER papers ready and formatted and edited, along with the task of getting the IEPR out that's going on right now, it got to be kind of too much for the technical editing part. But they will be available, I would guess, certainly by the end of the year, if not sooner.

ASSOCIATE MEMBER GEESMAN: What type of external review process did they go through?

MS. BURTON: Each of the whitepapers was reviewed by one or more technical experts that are also have global reputations or national reputations in those areas.

This is just basically a very skeletal outline of how my talk is put together. You've heard a little bit about this already from Kelly and Larry. It's important to have space; and if you're going to do geologic sequestration you have to have the potential to do it. So that question needs to be answered. If your closet is full, there's no place to put the CO2, you know, punt and go home.

So the geology of the state, and where the point sources are located, and whether they're large enough are key issues before we even start the conversation and move to the next step.

How well California is positioned to

move forward is really the main focus of the Assembly bill, and this consists of three parts. And this is true whether you're looking at a complex technology like carbon capture and sequestration, or something as simple as a kitchen blender.

If you look at what it takes to get a new technology adopted, the technology, itself, has to be robust enough and fit the purpose. You know, you have to have a blender that's going to, you know, grind up the oranges and make the margaritas.

Economic considerations. The price has to be right. Regulatory and statutory readiness. You have to have something in place that will protect both the manufacturer or the industry that is implementing the technology and something that will protect the consumer or the public.

And whether that's, you know, calling the Consumer Protection Agency when your blender flies apart in your kitchen, or some protection for the manufacturer that says he has a good business case to use this technology. Either way, that framework has to be there.

Again, just want to emphasize that CCS

is just a very new technology and we have to think in that context and not think of it as, you know, something weird just because it's something we're trying to do in this geologic subsurface. It is a new technology.

And finally, once we've established that we can move forward, should we actually do that. Should we consider doing that in the state? What are the risks and what are the benefits?

ASSOCIATE MEMBER GEESMAN: And your orientation was to sequestration within California, itself, as opposed to California utilities with coal plants in Utah having an opportunity to capture and sequester there.

MS. BURTON: Well, we've addressed both to some degree, because as has already been discussed this morning and offline, the economics kind of drive you to look at coal. But, I think part of the story here is that there are some good reasons to do it in California. And I hope by the end of today that we get those points across.

There, you know, are advantages to kind of punting the whole thing across the state line and saying, we'll buy electricity if you sequester the carbon and it meets our goals, in terms of our climate change mitigation directives within the state.

But there are also opportunities within the state that I think we need to look at. So, the first bullet, sequestration potential depends on the suitability of the sites, the geology, and the location and the size of the point sources.

And this first bullet is something that the Geological Survey has been working on and is going to continue to work on. Do we have suitable sequestration sites in California. And the second bullet is do we have the large point sources that are close enough to those sites.

So I'm going to turn this presentation over right now to John Clinkenbeard, who will address the first point.

MR. CLINKENBEARD: Good morning. I'm John Clinkenbeard, and I manage the Mineral Resources Program at the California Geological Survey. And I've been asked today to kind of review some of the work that we've been doing the last few years related to carbon sequestration in California.

We got involved in this a few years ago when the West Coast Regional Carbon Sequestration

Partnership started up. What I'd like to do is summarize mostly our work in phase one, and touch briefly a little bit on some work we're doing in phase two.

For phase one we looked at the sedimentary basins in California. And we started out with a list of 104 basins spread around the state. We looked at the geological literature on those basins and the other information that was available on those basins to try and determine if they had the potential for the geologic sequestration of carbon.

In that process we eliminated some 77 of these basins. Most of them were eliminated for one of four reasons. They either lacked porous and permeable formations; they lacked someplace to put the CO2; they had a lack of a suitable seal, they didn't have a capping formation that might help prevent the migration of CO2.

They had a sediment thickness of less than 800 meters. When you heard them talk about critical state injection of CO2, that needs to be done at something below 800 meters, which is a little over 2600 feet, in order to be able to inject that more or less as a liquid.

And finally, we did do a little bit of a cultural exclusion. We excluded basins that were mostly within parklands, tribal lands or military installations. And most of the basins we excluded for those reasons were down in southeastern California.

So, after looking at all these we ended up with a list of about 27 basins that met the screening criteria.

Here on this sheet you can see the results of that screening. Basins that show up there it looks to be sort of a bluish color are the excluded basins. And you can kind of see a lot of those are basins out here in the southeastern part of California.

A lot of those are basins that were either too shallow, for the most part. Some of those were basins that had cultural exclusions.

The central valley, the Sacramento/San Joaquin basin is probably the largest, but there are also several other basins that are included in the list of those that have some potential.

The geology of these basins out here is somewhat different than these basins over here. Some of that determines whether they have more sequestration potential or not.

This shows the oil and gas fields in California overlaid over some of the basins. And the 27 basins that are included do contain most of the hydrocarbon-producing basins in California. The larger marine basins. You can see much of the gas production in the northern Sacramento Valley. Mostly oil down in the south.

You will note here this is the Santa Maria Basin. We excluded the Santa Maria Basin because most of the production in Santa Maria, most of the hydrocarbon production comes from a fractured shale. So instead of having a sandstone body to put it into, it's in fractures in the rock. And we were less certain about exactly how to go about modeling or assessing the sequestration potential of that.

I am going to sort of use the Sacramento and San Joaquin Basins as an example. What we did, we looked at the oil and gas fields, we looked at the available information on the oil and gas fields to get an idea of things like permeability, porosity, fluid chemistry, some of the different parameters that helped other people in WESTCARB model some of the potential for carbon sequestration. We pulled a lot of that from the Division of Oil and Gas and Geothermal Resources records.

Sacramento/San Joaquin Basin is obviously the largest basin of the group. It's extensive; it covers over 22,000 square miles. It has large areas that are fairly sparsely populated, as opposed to something like the L.A. Basin, which is densely populated.

For California it's relatively tectonically stable. There's not a lot of active faulting. Depths range from about 800 meters to over 12,000 meters. On the west side of he valley there are places where the sediments are probably over 40,000 feet thick.

There are abundant saline formations; also oil and gas fields. Those are areas where we pulled data from. Porosity and permeability are fairly good. Porosity is the amount of void space in the sandstone, so that's the place where you can put the CO2. Permeability is a measure of how interconnected that space is. If you have isolated spaces you can't get the CO2 there. If they're connected, then you can pump the CO2 in.

PRESIDING MEMBER PFANNENSTIEL: How

important is the seismic stability? You say just kind of relative because it's California. What do you rule out, or did you rule anything out on the basis of potential seismic activity? Or where is your cutoff point?

MR. CLINKENBEARD: We didn't at the first cut that we did. That would have to be looked at as you come down more regionally and more site-specific. Some of the oil and gas folks can probably better address this.

I know, you know, when there are earthquakes sometimes there's damage to wells in oil and gas fields. I'm not sure that there's ever been a catastrophic failure due to an earthquake.

But I think that's an issue that you would have to look at on a more localized basis when you got to siting it, you know, whether you were close to an active fault or not.

What we did where we had the information available in phase one is we created a couple maps. One of these is a depth to basement map. This, again, is the Sacramento/San Joaquin Basin. You can see the red line along the eastern boundary is the 800-meter line. So everything to the west of that is deeper than 800 meters. So essentially everything to the west are areas that have enough sediment to have some potential if they have the right kinds of sediment.

This is a generalized cross-section of the southern Sacramento Basin, probably runs through Rio Vista area. As you can see, and as Larry discussed, you know, other states have more or less layer-cake geology. Everything just sort of runs fairly level, dips very shallowly.

It's a little different in California. But you can see here in yellow are formations that contain a lot of sand. The grey or blue formations are shales. These are finer units that may represent a boundary to the migration of CO_2.

We do have faults. And there are probably a lot more faults in here than actually show at this level, but here are some of these stratigraphic traps that Larry has talked about, or structural traps. This is a pinch-out. So there are areas within this that may provide sequestration potential.

Here's the southern San Joaquin. Notice you have even more disruption in the geology. Things dip steeply; but there are still pinch-outs in places where carbon might be sequestered.

As part of this where we had the information we created a gross sandstone isopach map. Isopach just means an area of equal thickness. So, this map shows a collection of all the sands. It doesn't show any specific geologic formation, but what this does is it shows the areas where there are more sand versus less sand.

So you can see in areas like this, these are areas that have, you know, 1000 or a couple thousand feet of cumulative sand in the subsurface. It doesn't define specific geologic units, but it just gives an idea where there is more sand or less sand.

So where we have the information available we did this. We didn't always have this information available. We were much more likely to have this information in those basins that have oil and gas fields in them, because they have the drilling, we have the records to do it.

In some of the desert areas we didn't have that information because there hasn't been the amount of drilling to determine that.

So the conclusions we came up with in phase one. There are 27 basins after the first initial screening that probably have some potential for CO_2 sequestration. The aggregate area is more than 38,000 square miles.

The cenozoic marine basins, those I pointed out kind of to the west, have the most potential. Amongst the most promising geologically are probably the Sacramento and San Joaquin Basins, and then places like Ventura, Los Angeles and the Eel River Basins.

Some of the people I think either at Livermore or MIT took our data and did an initial calculation with the ten largest basins and determined that there was capacity of something approaching 75 to 300 gigatons of CO_2. And I believe 75 gigatons correlates to something like 500 years at the current production rate. You know, these are initial estimates based on a crude first pass. The numbers will change, but at least gives us a sense that there is some potential there.

And in any of these cases, you know, before we decide where we want to sequester CO_2, obviously there would need to be much more, and a much more detailed look at those areas.

As part of phase two of WESTCARB we're

preparing some isopach maps of specific formations in the southern San Joaquin Basin. These include the Starkey, Winters and Mokelumne River formations.

This is the area of the southern Sacramento Basin that we're looking at. Here's a draft of one of the maps. We're reproducing a series of three maps. There'll be a depth-of-sand map; there'll be a net sand isopach; again, this shows the thickness of sands in the subsurface. And there will be a shale thickness or a thickness of the unit overlying the sand that may form a barrier.

So, on here you have a zero line out here, and over in here is the deepest or thickest part of the sand in the Mokelumne River formation. You also see on here several structures labeled gorges. Here's the Martinez Gorge, the Marklee Gorge and Meganos Gorge.

This represents areas where when these sediments were being laid down, these were submarine canyons like we currently have off Monterey. So these were large submarine canyons that periodically large amounts of sediment came and dumped down. And these actually cut into the underlying formations. In some places they may cut through the sands; you may have traps up against the gorge. In other places they may just come over and dig into them.

Anyway, this is the type of work that we're doing now. This will allow us to better refine the estimates and look at a specific formation and say, okay, here's potentially how much CO2 we might sequester there. It is kind of the second look. But, again, even this is still only a preliminary look related to what we would want to see done to actually determine where we were going to sequester CO2.

And I think that's all I have. If you have questions, I'll answer them. Otherwise, I'll turn it back to Liz.

PRESIDING MEMBER PFANNENSTIEL: Questions? Yes, go ahead.

SUPERVISOR BOPP: John, thanks. I'd like to address the concern about seismic risk. In thinking about it, seismic risk is always going to need to be considered, but just think probably the most active seismic basin with oil and gas production is the L.A. Basin.

And yet even there you've got huge oil

fields, Long Beach, Wilmington, Inglewood, that are really right on active fault lines. And yet the oil and gas traps are of geologic time. So I think in general it's a very optimistic scenario that seismic would not be a risk.

When you get into the saline aquifers, that's another question that's really got to be looked at.

MS. BURTON: I think as we move to our panel discussion this afternoon, too, I think there'll be some additional opportunities to take up things like seismic risk and some other issues that have come up with our panel of experts, too, if you'd like to.

Moving on, just to sum up, and again this reiterates with a little more detail of figures that Kelly had put earlier and that John just presented in terms of how they were derived.

The oil fields, and this was data collected by MIT for WESTCARB, they looked at all the oil fields in the state where they could find data and came up with about 3500 million megatons of capacity.

Gas fields also have storage capacity; about 1700. And saline formations are obviously the big gorilla in the room with the largest capacity. And just to put that in perspective, think Kelly touched on this, as well. If we just looked at instate power plant greenhouse gas emissions, those are about 47 million megatons of CO2 per year. So we have more than ample capacity in the state to put all of those emissions away, could we capture them, economically, for hundreds to thousands of years.

Again, this map seems to be quite contentious and we all managed to put it in our presentations. So the largest point sources in California are not coal plants. Natural gas power plants are the top categories in terms of size.

Refineries we consider as point sources, although it was brought up that within a refinery there are lots of little point sources. But still, they're geographically co-located, and it's possible to collect them all, stuff them in a pipe and sequester them.

And cement plants are actually a very significant source in the state, as well. And based on the MIT study 90 percent of these large point sources are within 50 kilometers of a potential sequestration site. So we don't really have to build a huge, long-distance pipeline structure to do this in the state.

The recommendations, based on this part of the study. There's really two of them that stand out. And these are a parallel to the long list that Kelly gave in his presentation. And I've just broken them out in the context of the technical background that I hope supports them.

Characterization of saline formation storage potential obviously needs refinement. We've got everything from 75 to 300 here. And we really need to look carefully as John and his team are doing at constraining those numbers.

And as Larry mentioned and Kelly mentioned, and you'll probably hear more people mention this afternoon, demonstration projects are really key to proving this technology. And particularly in saline formations, which we know a lot less about because the oil and gas industry has really covered the oil and gas potential reservoirs.

So, doing those demonstration projects for saline formations is really an important step to moving CCS forward.

ASSOCIATE MEMBER GEESMAN: Let me ask

about that last point. It would seem to me that taking advantage of the knowledge gained by the oil and gas industry, and potentially their economic interest in use of CO2 to enhance further production, would argue that those particular sequestration sites would be a priority.

MS. BURTON: Absolutely. I think the economics -- this is me speaking without a hat on -- I think the EOR, CO2 EOR combined with CCS are going to be some of the first projects that happen because the economics make sense, and we know a lot about those depleted oil and gas fields.

ASSOCIATE MEMBER GEESMAN: But you just said that the saline formation should be a priority for demonstration projects.

MS. BURTON: I think because we know less about them, and that's where the big capacity is. With respect to something like DOE's demonstration program, they're very focused on the saline because they need that.

Industry, there are -- and we don't know the details, but there are several projects that are in the planning stages right now for CO2 EOR combined with carbon capture.

So I think the thought is, and Larry can correct me on this, but that industry is moving forward with those early initial projects as demonstration or as small-scale commercial projects, where they have that economic driver. And it will fall to WESTCARB DOE to look at the saline and get that kind of hammered down a bit better through that demonstration program.

ASSOCIATE MEMBER GEESMAN: But if I recall two charts ago you showed that oil fields and gas fields would provide hundreds of -- I think it was the chart before this --

MS. BURTON: -- the table.

ASSOCIATE MEMBER GEESMAN: Yeah. If I calculate the number of times 47 goes into either of your oil fields total or your gas fields total, we're looking at hundreds and hundreds and hundreds of years of storage potential without getting to the saline formations.

MS. BURTON: That's correct.

ASSOCIATE MEMBER GEESMAN: Okay.

MS. BURTON: Do you want to chime in? Yes.

DR. MYER: So we don't necessarily -- this is Larry Myer, for the record. We don't necessarily want to take an attitude where we only put CO2 in the gas reservoirs and the oil reservoirs.

For one thing they may not always be in the locations that are best for us. This is a very cursory kind of analysis that we've done. And we may find that the storage characteristics are, and particularly the volumes in any particular reservoir may not be suitable, or what we would best want for a particular project.

So I think we recognize that, yes, there's an early opportunity associated with these. But we need to look at the long-term, the larger potential opportunities associated with the saline formations as -- even now begin to look at those and characterize them and develop the information we need to utilize.

ASSOCIATE MEMBER GEESMAN: Because they're there.

MR. FRIEDMANN: Larry, could I add something to that quickly?

DR. MYER: Come up.

MS. BURTON: This is, just by way of introduction, this is Julio Friedmann from Lawrence Livermore National Laboratory who was our --

ASSOCIATE MEMBER GEESMAN: Make sure the green light is turned on --

MS. BURTON: -- our expert for site characterization.

MR. FRIEDMANN: Yeah, and I'm going to be back again as part of the site characterization panel.

I just wanted to add to what Larry and Liz have already put forward. Part of the reason to put a priority on the saline aquifers is to understand and provide the information needed to develop regulatory frameworks and legal frameworks.

We already have those in place for work in oil and gas fields. And so those aren't seen as an important gap in terms of short-term deployment. Whereas, if we are going to, at some point, take advantage of that resource that's in saline aquifers, that it's important to learn what we can in the near term so that we can craft sensible policy around that information.

ASSOCIATE MEMBER GEESMAN: But would we be better off focused on that near-term deployment and the issues surrounding that, rather than trying to address these longer term issues in the abstract without the benefit of actual projects associated with them?

MR. FRIEDMANN: Well, again, the actual projects are coming. And it's --

ASSOCIATE MEMBER GEESMAN: Actual commercial projects?

MR. FRIEDMANN: Yes, actual commercial projects are coming. And it's important to note that we already have a lot of information from the oil and gas fields, as you've laid forth. And there is a lot more information to be gathered.

Like any other resource, any other natural resource, you want to know whether or not it's reasonable to exploit it and how. And it's in exactly that context where information is useful.

I'm not speaking on behalf of the CEC, so I just wanted to add that perspective in terms of what was already said. And, again, I'll be up later. You can continue to ask me questions then.

ASSOCIATE MEMBER GEESMAN: Madam Chair, I see someone else with their hand up.

PRESIDING MEMBER PFANNENSTIEL: Yeah, somebody else to comment on this, go ahead.

MR. HAERTER: If I could introduce myself, I'm James Haerter; I work for the Bureau of Land Management, the U.S. Bureau of Land Management here in Sacramento, California. I'm the Oil and Gas Program Lead for the State of California, for BLM.

In direct answer to your question I think, by point of clarification, the importance of looking at saline reservoir formations is for potentially the situation that will arise where the economic interest of enhanced oil recovery is distinct or less of economic benefit than the public interest driver that may require sequestration of CO2.

If it doesn't make sense economically, and if it isn't in the interest to inject that CO2 into a hydrocarbon reservoir, either oil or natural gas, then what you're doing is usurping the mineral interest of that oil or gas operator, or of the federal interest a the mineral interest owner in deference to the public interest requirement.

Having a saline reservoir capability, injection capability, I think, is a critical component of this process.

ASSOCIATE MEMBER GEESMAN: I'm not certain I follow what you just said. I'm sorry. It would appear to me though that if, in fact, the public interest compelled capture and sequestration that it might be a lot more economic, as a policy, to compel that sequestration in a gas field or an oil field than in a saline formation.

So I'm not certain that I perceive the conflict with the public interest.

MR. HAERTER: It's not a conflict with the public interest. It's a conflict with the mineral interest. And in this the federal government does have primacy.

If it is not in the interest of enhanced oil recovery, then it is not in the mineral interest of the United States for carbon sequestration.

ASSOCIATE MEMBER GEESMAN: Okay, that's more clear.

MR. HAERTER: Thank you.

MS. BURTON: I guess that actually touches on another thing, is the issue of mineral rights, which is obviously potentially contentious for the first two reservoir types.

The other thing that, and maybe this is, to some extent, our fault for peeling it out and making these distinctions, in an oil field there are saline formations. All you have to do is drill the well a little bit deeper; and oil companies often dispose of produced water and other things into those saline formations.

So you could have one well that is actually sequestering CO2 in all three of these types of reservoirs or one operation.

So, to some extent we're probably at fault here for making those things, you know, too silo'd. So.

Okay, second point. How well is California positioned to move forward. And the first of those issues is technical readiness. And this is really where the primary focus of the AB-1925 report lies, with these three upcoming bullets.

And of these there are a number of components of technical readiness. Kelly's already listed these out as components that the bill wanted us to address. And I've changed the order a little bit to kind of follow the things that you would do first with surface facilities, capture technologies and transportation. And then the subsurface technologies that are necessary to do the sequestration.

And this includes site characterization, monitoring and verification, risks and risk management, which again the issues here are the subsurface risk. We know a lot about how to manage the surface risk of facilities already. And the remediation and mitigation procedures that you would follow should a leakage event occur.

Capture methods. There are really three that kind of come to the fore in terms of current commercial technologies or almost commercial technologies. Top left, precombustion. This is done for syngas production already to produce hydrogen at refineries and so on. EOR uses this process. Weyburn EOR and CCS Project up in Canada is using this process. And it's, I believe, what is planned for Carson.

And the idea here is that you start out with the gas and you add steam; do a water/gas shift reaction. Along the way here you're producing hydrogen and carbon monoxide. And then when you add the water you shift back to oxidize the carbon monoxide even more if you want to remove that; or you can stop and just have a carbon monoxide/hydrogen rich syngas formulation for the chemical industry, for example.

But in any event, what you end up with at the end is a hydrogen stream and a relatively pure CO2 stream. And that's what you're trying to get to with any of these capture-and-separation processes, is as pure a CO2 stream as you can manage for lowest price.

Post-combustion is commercial; it's used a lot for natural gas processing where they need to remove the CO2 from the methane. This is typically done by a chemical process; amine stripping in a tower or something to that effect.

And then oxyfuel combustion generally is not commercial yet. And this is basically where instead of air you're adding oxygen so you eliminate all of the nitrogen and you end up with a much richer CO2 stream of emissions. But they do use it, I guess, for ore processing and for some chemical processing at this time.

So, in general, most of these have not really been used at any large scale on power plants yet, but they're ready to go. They have been commercially proven in other venues.

Generally the way you get to --

ASSOCIATE MEMBER GEESMAN: Liz, can I ask you, on those techniques, would you see similar techniques being used within a refinery or a cement plant?

MS. BURTON: Refineries use the pre-combustion to make their hydrogen. That's basically the part of their hydrogen plant.

Rich, what commercial -- cement --

MR. MYHRE: Yeah, on refinery boilers --

PRESIDING MEMBER PFANNENSTIEL: Rich, you need to get to the mike so we capture the comment.

MR. MYHRE: Again, this is Rich Myhre just adding a clarifying remark. You had also asked about the number of point sources within a refinery earlier. While there may be many, there will be a relatively small number of large ones, and those would be the ones of interest.

And in refineries you are heating up the crude in a -- you basically have furnaces and boilers. And those are not all that dissimilar from the sort of boiler you would have in a conventional fossil fuel boiler power plant.

And so you would be using the post-combustion process on boilers and furnaces in a refinery. And then the hydrogen plants, some of them on their own produce CO2. There may be other processes within a refinery where you can apply this water/gas shift reaction and get purified CO2 streams.

But on a volumetric basis of CO2, I think the majority of applications in a refinery would be post-combustion.

ASSOCIATE MEMBER GEESMAN: And no comment on the cement plant, which was your other large point source?

MR. MYHRE: I'm going to go out a little bit on a limb here. The cement plants, I know, have been looking at two different technologies. And one of them involves what they call pressure swing absorption, which is the technology that's used in precombustion. Although you do not have the gas streams at the high pressures you typically do, for example, coming out of a gasifier for coal or petroleum coke.

So, I think I will say it's a hybrid of these sorts of technologies, but it's not a fundamentally different family.

MS. BURTON: Does that cover the bases?

Okay.

Factors that decrease capture costs. There are primarily three of them. The higher the fuel source is in carbon, the higher the concentration of CO2 is going to be in the emissions. The larger the volume of the gas stream, the more economy of scale you can realize. And the lower the fuel cost, because you actually use energy in capture and compression.

So, this leads us to the conclusion that you've all already made, capture costs are lowest for large coal-fired plants. So I mean there's no way around that given our current technologies.

This, I think, goes to some of the questions also that were raised earlier. The point sources in California, again coal power is shown by the little gold bars, way over there, tiny sources. Although there are actually a fair number of them, but they're all fairly small. The big players are the gas, natural gas power plants in the state. Over to the far left those are all the purplish-red bars.

Cement and refineries are also fairly significant in size, although again small number of facilities. But these are obviously, I think, your first targets if you were to do this in the state, would be those things off to the left side of this graph.

ASSOCIATE MEMBER GEESMAN: And this is a graph of actual plants?

MS. BURTON: Yes. This is, again, data collected by the WESTCARB/MIT study. And I think supplemented during the whitepaper exercise, looking at actual, you know, plant-by-plant.

ASSOCIATE MEMBER GEESMAN: And do you know how they collected that?

MS. BURTON: Do you know what database they used, Larry, to do this? Or -- I --

MR. MYHRE: Again, Rich Myhre attempting to add clarification. I'm not certain, but I believe it would be the EPA e-grid database.

ASSOCIATE MEMBER GEESMAN: So I see a pretty large spread for the emissions assigned to different gas plants; and I would presume that's a function both of heat rate and the number of operating hours in the observation period for that particular plant?

MR. MYHRE: Again, Rich Myhre. These are for plants, as opposed to units, and so I think the biggest factor would seem to be the number of units that they have on site. And then, yes, the other factors would be capacity factor and then heat rate.

To have that much CO_2 they're probably combined cycle plants. And so the differential heat rate between combined cycle plants is significant, but not nearly as much as the distinction between a combined cycle plant and a simple cycle plant.

The simple cycle plants are your peakers, by and large. And so they would be sort of off the chart on the right end.

So these are almost certainly combined cycle plants operating at pretty high capacity factor. So I think the biggest difference would be the number of units at the plant, itself.

ASSOCIATE MEMBER GEESMAN: Okay.

MS. BURTON: Yeah, unfortunately Howard Herzog and his team, who did this study, were not able to attend today, or we could actually get that information direct from the source. But we'll follow up on that and confirm. Rich's been somewhat involved in this, as well. But we can confirm for this chart, in particular, with

Howard.

SUPERVISOR BOPP: Liz.

MS. BURTON: Yeah.

SUPERVISOR BOPP: A general question, and maybe there's not an answer for this, but I'm wondering, so we're back again to a large source of CO2 emission relative to the State of California is generated offsite -- outside of California from large coal power plants.

And yet I'm just wondering if in your study there was any thought given to -- it seems like part of this is -- you know, because one approach would be the state could say to those power plants, well, you know, you've got to sequester your carbon or we're not going to buy your power.

But isn't there some benefit to California taking a leadership role, I guess is one way to put it, by taking this approach of sequestering what's generated within the state.

Was there any consideration given to that as kind of a policy approach --

MS. BURTON: Well, we actually wanted to avoid policy. But, you're right, you're absolutely right. I mean you're left with this choice of, you know, that 61 million tons of CO2 that's generated by out-of-state power.

If we said, you know, all of that has to be also have carbon capture associated with it, you know, is that sufficient for California, as an approach to greenhouse gas mitigation, you know. Do we just say we're not going to buy power unless it's, you know, completely carbon neutral? Or do we want to actually pursue carbon capture with our instate power, or with some of our other large industrial facilities?

And that is exactly a policy question. We wanted to try and lay out at least a preliminary idea of how you might go about informing that policy decision. And this report is definitely just a preliminary look at that.

We don't have, you know, the kind of cost-to-generation analyses that are done at the Energy Commission to really, you know, support a policy one way or the other. And we would like to do that between now and 2010.

ASSOCIATE MEMBER GEESMAN: Yeah, I guess a concern that I would express is the capacity factors can change pretty radically from year to year for particular plants. And as an energy policy we can replace those gas-fired plants with something else, energy efficiency or renewable sources of electricity have been our policy preferences for a number of years.

I'm not certain that we can replace the refineries. And as a consequence, despite the appeal of wanting to do everything, unavoidably you need to prioritize.

And I do think, as we get into the economic discussion later today, I suspect economics will probably have a pretty strong role in prioritizing.

MS. BURTON: I think there are a number of scenarios that you could do a more definitive analysis for; and form, you know, which way makes the most sense to go. I think that definitely is something that comes out of this report.

Okay, again, we've probably actually covered this slide already, but carbon capture for coal implies a focus for California on imported power. Again, about 60-, 61-million megatons of CO2 per year. And we have the emissions standard in Senate Bill 1368 which prohibits long-term power purchase agreements for baseload power if the emissions are greater than that standard.

And if you add CCS to that mix, that puts the plants well below the standard, but it will significantly increase power costs for those plants. And that changes the whole paradigm scenario analysis. And that needs to somehow get factored into planning.

Okay, so early economic opportunities in California lie, we think, in two places. And, again, we've already talked about these to some extent.

Ethanol. John Kadyszewski, if I'm pronouncing his name right, is also a member of the WESTCARB Partnership; works on terrestrial sequestration. He talked extensively at the May 29th workshop about ethanol. And I just refer, for the specifics, back to his presentation without reproducing it here.

But basically there are two large plants in California, and a large number also in the planning stages right now. John has a nice map in his presentation of where those are. They correspond, again, pretty nicely to potential sequestration sites.

The fermentation process creates about 2500 metric tons of CO2 for every million gallons of ethanol produced. And the emissions are essentially PIER CO2, so you don't have that big, nasty, upfront capture cost to deal with if you combine CCS with an ethanol plant.

Hydrogen, again, through that precombustion process, if you're making hydrogen fuels, or if you're doing syngas, CO2 capture is an integral part of that process and may be easily incorporated at much lower economic costs than slapping it onto a power plant.

If we look at EOR, again, so this wold be kind of the second early opportunity, which again we've already discussed. Just breaking down Howard's numbers, reproducing the first line of the table that same data, oil fields with storage potential. And now looking at which of those have also the potential for CO2 EOR.

And you can do a CO2 EOR flood either emissively, where the CO2 actually is not present as a separate phase in the hydrocarbon reservoir.

And most of the oil fields in California do fall within that category. So there seems to be, at least at a first cut, a fairly large potential to do CO2 EOR in the state.

Emissible is another way where the CO2

is actually flowing as a separate phase, and there are a small number of those, as well. And really not very many that don't have EOR potential at the same time.

So, adding all of those up we have about 80 percent of our large emission sources within about 50 kilometers of a potential EOR site. So, again, it looks pretty good as low-hanging fruit.

ASSOCIATE MEMBER GEESMAN: Is there a difference in injection technique between a missible and emissible form of EOR?

MS. BURTON: Usually what's driving emissibility is both the nature of the oil and the depth and temperature. And to the extent that those things would also change the way you did the injection, yes. But fundamentally the technology for injection would be the same.

If there's anybody from the oil industry that wants to correct me, -- if that's okay, we'll just leave it at that as a simplistic.

Okay, moving on --

SUPERVISOR BOPP: Liz, I wanted to bring this up earlier, and you raised it just to further confuse the issue, I guess. Understand that there is the possibility, as was pointed out in that last slide, of having a non-EOR injection project into an existing oil and gas reservoir.

You know, EOR demands that and we've got guidelines for it, that there actually be enhanced recovery of some sort.

And actually that's one of the areas that in the Interstate Oil and Gas Compact Commission model regs and statutes, that issue gets addressed. You know, the possibility that you could be conducting an EOR project in an oil and gas reservoir, and at some point it may become storage, instead, when there's no incremental hydrocarbons being produced.

ASSOCIATE MEMBER GEESMAN: But this chart would say the overwhelming majority in California would likely fall into the EOR category.

SUPERVISOR BOPP: And I agree with that.

MS. BURTON: Yeah, and again, this is just from the standpoint of looking at the characteristics of the field, not from an economic standpoint at all. So that is still out there, whether this actually holds true once you throw the economics in.

For transport, we got pipelines all over the place. There are lots of CO2 pipelines in other parts of the country. Not so many here in the state, so the technology for pipeline transport is very well established. We have a very experienced workforce. So in terms of technical readiness, transport is not an issue.

The regulatory framework, the Office of the State Fire Marshal has jurisdiction here. And he says that there's really no problem with incorporating CO2 pipelines into the existing regulatory framework.

But, with regard to doing CCS in California we don't have a pipeline infrastructure, and we don't have one to do EOR, either. So there's an issue here certainly in trying to figure out how to get that infrastructure up and running. It's billions of dollars invested in the Rocky Mountain states where they do CO2 EOR and New Mexico, and so on. So it's not really a trivial issue in terms of moving us to step two.

Recommendations. Again, from the capture and transport part of this study. More research and development is obviously needed to try and get those costs down for capture and to improve efficiencies.

Further evaluations are needed of issues surrounding pipeline infrastructure. And further evaluation needed of the potential for geologic sequestration via EOR and in combination with ethanol production. So do those early opportunities really make sense when you do a detailed analysis of them?

Moving on to the next part. Sequestration. So now we're going underground. Site characterization and certification, risks and risk management, monitoring and verification, remediation and mitigation.

And rather than think laundry lists of technologies, I kind of took a much higher level approach to this. But you can think as we move through for site characterization, monitoring and verification, Larry touched certainly on some of these. But there's a very well established set of technologies primarily coming out of the oil industry to do site characterization, monitoring and verification, and to do particularly well failure remediation, as well.

So I did not actually go through a laundry list of what those are. They are itemized in the report, so I'll just refer that to you.

So, hitting the highlights for these technical components, subsurface is the focus again of AB-1925. For the surface, site characterization techniques are very well established. And right here in the Energy Commission you do siting for power plants.

And in talking with the staff here, they brought this to our attention. And this is really the yellow bullet, that adding CCS to new or existing power plants has some potential effects on the regulatory frameworks that are currently in place for permitting those power plants.

This includes CEQA and Warren Alquist, and this includes both siting new plants as well as doing retrofits. So this is going to have some impact on their operations if we do CCS in the state.

The Energy Commission will be the CEQA lead agency for CCS probably; and this aspect needs to be included in any follow-up studies that are done for the next report.

Goals of site characterization. And, again, we could probably reiterate this list for monitoring and verification for risk assessment.

And part of the message with this is that there needs to be some integrated approach that includes all of these components when we start thinking about what will be required when we are regulating these sites.

So I spell them out for site characterization, but you can also think of them as applying to the other technical components.

Assess the key parameters of the site. Identify the site-specific risk elements. And then provide data, both to inform permitting and to, in the case of site characterization, inform facilities planning. Everything from where you put the surface facilities to where you put the wells and where you put the monitoring equipment. And how much you need.

Site characterization subsurface. There are three key parameters, and this, I think, relates to some questions we had earlier, as well. Injectivity is a very key thing. If you can't get the CO2 into the formation, you have a real problem. Realizing your capacity for storage. Capacity is the total volume that you can store. And effectiveness is probably the crux of the matter. Can we actually keep the gas in that reservoir for the hundreds to even thousands of years that we need to if this is going to be an effective climate change technology.

Technical readiness to do this sort of site characterization. Again, the oil industry has been characterizing the subsurface for years. There's lots of existing technology around. There are laundry lists in the report. There's lots of relevant knowledge and experience in the oil industry that we can use.

And there are many analogues. And a lot of the work that's going on now in the partnerships and in some other Department of Energy-funded research is to understand what we can learn from these analogues; what is relevant and what may not be.

There are many natural CO2 reservoirs around the world, and several in the United States. These are used for CO2 for EOR operations. CO2 is stored, to some extent, by EOR. And we can learn a great deal by looking at what's been learned over time from those operations.

Natural gas storage is also not a bad analogue for some aspects of this, although CO2 is a very different kind of gas than methane; and that point does have to be remembered.

And then ongoing and upcoming CCS projects worldwide, which Larry summarized quite nicely earlier this morning.

Site-specific risk elements that need to be assessed. Generally leakage is the big one. And the idea is that, you know, we certainly don't want a leakage of CO_2 to harm people or the environment or to damage property.

And there are a number of ways that CO_2 can leak back out. Pipelines is one of them. And interestingly enough when the Future Gen environmental risk assessment was done, this is really where they focused on as being one of the higher risk factors. So it's not the subsurface; it's the pipeline.

So to some extent, if they're correct, we tend to worry more about the second one, leaks from a storage reservoir; but maybe that is somewhat misplaced. At least their risk assessment would tend to suggest that.

The storage reservoir can leak through wells, faults or other breaches in the cap rock. And the CO_2 could potentially get to groundwater, to mineral deposits, natural gas or oil deposits, which may be a benefit, may be not a benefit. Or it can come back to the surface potentially.

And we have to understand, when we do site characterization and risk assessment, how to actually quantify those things and avoid them if we can.

There's also climate change risk. So, I mean, what's the point of doing this if it ends up back in the atmosphere in the long run. I mean it's a big waste of money and time and effort.

And the other risk, induced seismic from over-pressuring. And there actually is a fair amount of data, again from the oil industry, as well as some other operations where we've done waste injection, which can inform how to avoid producing that problem.

ASSOCIATE MEMBER GEESMAN: The expected life of the pipeline, though, is a small fraction of the expected life of the reservoir, is it not?

MS. BURTON: That's correct.

ASSOCIATE MEMBER GEESMAN: And yet DOE still found a significantly higher risk associated with the pipeline?

MS. BURTON: Well, not DOE, but the

people that did the risk assessment. That was TetraTech was --

ASSOCIATE MEMBER GEESMAN: Okay.

MS. BURTON: -- and their focus there, rightly or wrongly, was really on pipeline leaks and not so much of the CO_2, but of the trace gases like hydrogen sulfide that is lethal in very small quantities.

And, again, we talked about this offline earlier, you know, that report used standard techniques to do a risk assessment, rightly or wrongly, but it's out there and it does, as the first one for CCS sites, something of a precedent; needs to be looked at carefully.

And you're absolutely right, there's a time scale issue there.

PRESIDING MEMBER PFANNENSTIEL: You mentioned that we'd need a new pipeline infrastructure somehow. Implying then that we would be building new pipelines, somebody would, from scratch. Does that imply a different type of pipeline? Is there a different material? A different cost of pipeline that we would be building then if we were doing natural gas or oil pipelines?

MS. BURTON: It's possible, I believe, to retrofit some existing pipelines if there are any available to retrofit for CO_2. The biggest problem that I'm aware of for CO_2 transport is if it gets wet. It's perfectly fine to transport CO_2 if it's dry. The minute you have any water vapor there, it becomes quite corrosive because CO_2 then becomes an acid, and it can corrode your pipelines.

On the other hand, CO_2 EOR pipelines all over the west have learned how to avoid those problems. There are people in the audience, I know, here, who could comment on that much more knowledgeably than I can.

DIRECTOR LUTHER: I think the biggest hazard is seismic hazard on the pipelines because when you start moving volatile materials long distances the seismic activity becomes very high risk. I mean that's problematic across California on everything that we're transporting.

MS. BURTON: Right, right. But I think, I mean, we do have seismic hazard approaches for dealing with the pipeline infrastructure we currently have. And, you know, at least at a preliminary level I don't see any reason why those same types of approaches and safeguards couldn't be implemented on a CO_2 pipeline.

If anything, CO_2 is less of a problem than a natural gas pipeline because, you know, it's not flammable. In fact, we have fire extinguishers that are full of CO_2. So, you know, it's a much safer thing to leak out of a pipeline than a lot of other things that we currently transport.

MR. MYHRE: Rich Myhre again for a quick point of clarification to Commissioner Pfannenstiel's question. Typically the pipelines are constructed of the same sorts of steel materials that other pipelines are made out of.

The preferred operating pressure for a CO_2 pipeline is a little bit higher to take advantage of sort of this volumetric efficiency. CO_2 basically compresses down at higher pressures more than natural gas does. And you can reduce the energy required to move the CO_2 by getting it to that stage.

And so the pipeline that's most often cited is the one that travels from North Dakota to Saskatchewan. That pipeline operates at a little above 2000, or it's 2000-something, pounds per square inch.

Natural gas pipelines are, you know, high-pressure, natural gas pipelines are roughly about half that.

MS. BURTON: Okay. This is just in part to avoid the monotony of word slides, but also wanted to make the point that, you know, whether a leak is really a hazard depends very much on the site conditions.

On the left we have Mammoth Mountain. And as you may know sometimes the CO2 that leaks out of that whole volcanic system there does accumulate in low depressions where air mixing isn't sufficient. There were a couple of ski patrol people that died, I think, last year or the year before, because CO2 accumulated in a snow cave that was created by this warm gas. And one or two of them fell into that opening.

So, very very special, almost peculiar conditions, even at a place like Mammoth, which generally has fairly slow, low leakage that's fairly dispersed across this area. A lot of tree kills in that area.

Contrast with Crystal Geyser, shown on the right, where we have actually fairly large burps of CO_2 coming to the surface. This is a oil prospect well that was drilled; and they ended up intersecting a natural CO_2 reservoir. And then they just -- this is back in the '30s, '40s, they just, you know, walked away from it at that time. And it's become a tourist attraction. You can see lots of -- you know, there's lots of air flow. The CO_2 never builds up. And it's fun because it's a geyser, and you know, blows the water out along with the CO_2.

And, again, they're pretty large burps, much larger than any given burp from Mammoth Mountain. But the site conditions make a huge difference in the risk element for this.

So, again, risk assessment. The knowledge and the methods to do risk assessments that are appropriate for CCS are very robust, and they exist, and we can borrow them and apply them quite effectively. The relevant knowledge is there; the experience from looking at analogues such as CO_2 EOR pipeline, natural gas storage.

The challenge, I think, here, and again this relates back to Commissioner Geesman's question, the challenge is to do appropriate risk assessments for these long periods and large spatial scales that are involved with CCS.

But there's a lot of work going on worldwide to make those issues tractable and to develop specific frameworks. And one of those is a FEPs approach. Contessa did this as part of the Department of Energy or an IEA study. FEPs are features, events and processes.

And features was better to list examples than a definition. Reservoir perm, cap rock thickness, you know, whatever the parameters are that define the characteristics of the site.

Events are things like seismic events or well blowouts. And processes are the things that just go on, you know, everywhere, but impact the actual risk of something bad happening.

This can include chemical reactions, geomechanical changes that occur that can affect a storage effectiveness.

And there is a FEPs database that's been developed for CCS. And what this allows you to do is basically consider everything and then rank them in terms of their importance for a given site. And for California obviously you take seismic out of that database and deal with it. And then you can actually identify relevant hazard scenarios to look at from that. So I think we're well on the way to developing the appropriate risk assessment frameworks for CCS.

Monitoring needs to provide early detection of any significant leaks and to verify storage. Again, these techniques, for the most part, are borrowed out of the oil industry and work quite well for monitoring sites.

As Larry mentioned earlier, we're looking at a suite of monitoring tools, not just focusing on seismic. And the suite and the number of monitoring stations you might have, we think, should be determined site-by-site, because there are differences in the geology and the risks that would affect what you decided to do. What would be defined as fit for purpose.

Technical readiness, again the technology exists and the knowledge and experience for monitoring and verification come out of the oil and gas industry.

One thing that I think is important to bring up in this context, and again for remediation and mitigation, is that the way the CO2 is stored changes over time. So at the beginning of a project we're looking at CO2 that is trapped as super-critical CO_2 in the structures or in the stratigraphy, shown by that kind of purple part up at the top. So most of it is trapped that way.

Over time, the stuff starts to get integrated into the rock and its pore fluid, so we have residual trapping, and then solubility trapping where the CO_2 is actually dissolved in the pore waters. And then mineral trapping finally after a sufficient number of years. And you can see there's a shift over time to these other modes of storage.

And it's important, when you think about monitoring, to realize that what you're looking for changes over time. And there's also obviously a decrease in the risk of leakage over time because of this change in the way the CO_2 is stored.

So, moving on to remediation and mitigation, what to do in case of a leak. Again, we have significant experience in the oil and gas and the natural gas storage industry. The technology for remediating blown-out wells, for remediating leaking reservoirs does exist. And Vellow has provided some very nice tables and discussion primarily of the natural gas storage and how you can fix these reservoirs that end up leaking.

It's probably a good idea to think about collecting relevant best practices from these analogue operations, oil and gas industry, natural gas storage, deep waste injection, and put them together into a CCS-relevant framework. So that probably does need to be done.

Again, I think what comes out of this is that we need to look at site characterization, risk assessment, monitoring and verification protocols all together in an integrated fashion. Not just, you know, have one committee working on one thing and another committee working on the other. These things are interdependent and can rely on -- you can get the same information to inform all of those from similar technical tools.

And, again, evaluate and compile ways to respond to events and to remediate and mitigate the problem.

Another look at economics. This is the problem child, probably, of all the slides. And, again, these are preliminary estimates of what it will cost, and I kind of went back and forth with this; and most of the estimates that have been made are on a per-metric-ton-of-CO2 basis, not in terms of their cost to the electricity consumer, or whatever. But maybe that's not a bad thing, since some of those early sources may -- or early targets may not be power plants, but instead industrial sources.

So you can see pulverized coal, IGCC are the cheapest way to go. Once you move to natural gas you've added about $25 to the cost of doing capture.

I put some numbers that we had estimated, making some assumptions about capacity factor and so on, for pulverized coal and IGCC. About 30 cents per megawatt hour. I think -- no, I've screwed that up. I think that was $32 per megawatt hour, or 3 cents per megawatt hour. I apologize, I've got the decimal in the wrong place. PowerPoint decided I didn't know what I was talking about. So, there's an error there. There's -- two decimal places should be moved to the right on that, 32 and 24.

Pure industrial sources, some of the things we were talking about, that cost drops to about 10. Transport, there's economies of scale.

Once you get above about 10 million metric tons costs are about 50 cents.

Injection and storage can be anywhere between 50 cents and $8. This depends on the number of wells, the depth of the wells, the size of the wells. So those, again, are going to be very site-specific. Monitoring, 10 cents to 30 cents per metric ton.

One of the interesting things, again, when we talk about early opportunities, is if you have EOR estimates are that you can subtract $20. In other words, you have a $20 net benefit from doing EOR. And that starts to make natural gas look more competitive with out-of-state coal.

ASSOCIATE MEMBER GEESMAN: Your transport number must assume some distance?

MR. SPEAKER: I believe that's per 100 kilometers --

MS. BURTON: Yeah, yeah.

ASSOCIATE MEMBER GEESMAN: A hundred kilometers?

MS. BURTON: Yeah.

ASSOCIATE MEMBER GEESMAN: Okay.

MS. BURTON: Yeah, there's a graph actually in the report that has, an exponential decay curve in the economics section. And I just kind of took the number where that levels off. But that gives you the details of how they derive that function.

ASSOCIATE MEMBER GEESMAN: And I guess your point on the EOR bringing natural gas more competitive with out-of-state coal plants is only true if the out-of-state coal plants aren't also making use of the opportunity to sell their CO2 --

MS. BURTON: Right, that's --

ASSOCIATE MEMBER GEESMAN: -- for EOR?

MS. BURTON: -- correct. Yeah. So I guess, back of the envelope, to sort of think about that, the other thing that some of those states have is natural CO2 reservoirs that are already being tapped for EOR. So they may not have the same kind of market that California does. But that needs to be looked at in more detail.

ASSOCIATE MEMBER GEESMAN: That $20 cost is a California value?

MS. BURTON: I believe so. I think Howard did that specifically for California.

Existing regulatory frameworks. There's several options right now for incorporating CCS. The underground injection control program run by

EPA and here for class 2, the Division of Oil and Gas and geothermal resources.

The different options that have been discussed for class designation for carbon capture and storage injection wells. And somebody told me that EPA had made a decision potentially, but I haven't verified exactly where they are in determining the class at this point. I believe the jury is still out.

Natural gas storage is another possibility. This is done through the California Environmental Quality Act, or CEQA. None of these are really ideal for CCS. And Sarah goes into the details of where some of the gaps and ambiguities are. And I've reproduced them in the report pretty well from her whitepaper.

And there are also overlaps with existing industries that have different needs. And I think we need to be very careful as we move forward that we don't, you know, throw the baby out with the bath water, if you want; that we, you know, destroy EOR in general by trying to regulate it along with CCS, or changing those regulations. So there is kind of a cautionary flag here with that.

Regulatory needs. CCS is going to be a little difficult. We have different emission sources, power plants, refineries, cement plants, all subject to different regulatory agencies in terms of surface facilities right now. And we have different sequestration reservoirs. Saline aquifers are not regulated under oil and gas frameworks right now.

So, any CCS regulatory framework is going to need the flexibility, the streamline, predictability and consistency to deal with this myriad of different things that are involved in CCS.

On the other hand, the technology and the knowledge exist to inform the regulations. It hasn't been put together any better than this report, probably, but we need to move forward with trying to figure out -- we don't have to invent anything, but we do need to assemble it, perhaps, in a more detailed fashion to inform how to write those regulations.

And, again, to hammer on this demonstration, early projects are needed to provide the test cases. Before we get too far down the regulatory pathway maybe we should try a few things and see what happens.

Statutory frameworks. I've only got, I think, about five more slides, so I hope I'm not getting into lunch time too much here.

Two major issues for statutory issues. Ownership. Surface owners, subsurface owners. Pore space is the biggie here. Nobody's ever really worried about owning pore space before. And now it's something that we need to put CO2 into.

Mineral rights. Once you put the CO2 down there, have you disrupted somebody's ability to extract oil and gas now, or in the future. And water rights. A big potential if groundwater is contaminated, or if we have brackish aquifers that are storage sites today in water resources a thousand years from now. Who knows?

Liability, long-term stewardship. Leakage event liability for harm or property damage is one thing. People that are thinking about CCS projects are very concerned that there are no deadlines. It's basically unending liability, given the current statutory frameworks.

And then there's the climate change liability. What happens if it leaks a couple hundred years from now, who's liable for that contribution of CO_2 back into the atmosphere?

So, we have existing statutes that, you know, were not designed to do CCS. And there are ambiguities and gaps, specifically acquisition of rights and no time limits on liability are probably the two biggest ones.

Statutory needs. Again, this long-term nature is kind of problematic. Some way has to be found to assure long-term stewardship. And that's, you know, not just to keep industry from having heartburn, but also to protect the public and the environment. And we have programs like that already for orphaned wells, for example, and some other things that might or might not be good analogues. But that needs to be looked at quite carefully if we chose to do CCS projects with that kind of a program for turning over liability and stewardship.

Address ambiguities in ownership. You know, how do we do this? Public good versus private property rights. It becomes a big issue.

Define liability limits and how those follow ownership. And this starts to get very complicated when you start thinking about carbon credits. Because now CO2 has a value, and who owns that pore space and who owns that CO2. I mean it's no longer just an "eenh", you know, somebody put their -- it has value and that makes a huge difference.

So, recommendations again. There's a lot of work that needs to be done to evaluate statutory and regulatory uncertainties, and figure out what the options are for finding something that's appropriate for CCS. And, again, continuity, streamlining, flexibility are the key attributes. And we want integrated consideration of technical requirements. So we're not just, you know, setting one thing up and not thinking about the whole package here.

And, again, the gaps in statutory frameworks right now create business uncertainty that could be a major roadblock to moving CCS forward in the state.

And, again, my last bullet, should California consider it. What are the real risks and benefits. And Kelly talked about this a little bit already. Meeting California's greenhouse emissions reduction goals, there's certainly a consideration that, you know, has to be right up there in policy. Does CCS instate, out-of-state, make sense to get there.

Global and local risks associated with climate change. And particularly local risk, what are we asking local communities to accept if there's a CCS site under the neighborhood.

And, again, Kelly showed you this earlier. Carbon sequestration may be necessary to fill that gap. Can we get there with other alternative ways of reducing emissions. And generally, I think the expert consensus is we can't. We need something else to help fill this gap, whether CCS is it or not is another matter.

Risk perception will affect the rate of adoption. I mean there's no way around that. Risk components, occurrence of natural processes or events, engineering and technical factors, human error, and financial and economic parameters.

So, generally we have to get everybody confident that the overall risk in adopting the new technology is low, relative to the benefit. And that's maybe a little bit trite, but true, nevertheless. I mean it's easy to say. It's hard to get there.

And one way to get there is, you know, to stop talking to ourselves, as scientists, and get out there and get the public participating. I kind of did a very off-the-cuff survey and asked, you know, people like my kids' karate teacher and, you know, other people that aren't in a technical realm usually, you know, have you ever heard of carbon capture and storage. And uniformly the answer is no, you know. They don't know much about this.

So, we need to get the public informed about what it is and do outreach. And particularly the people that might end up being affected by this need to understand it and participate in the process.

And this is maybe the only slide I should have put up, but I tried to say, okay, if I had one slide and put everything on it, this would basically be a summary of the whole report.

Large geologic potential; large point sources, but not the most economic right now. But there are some near-term options. Now, out-of-state suppliers with coal plants, you can, you know, point the finger and say, you know, we won't buy electricity unless you do CCS. That's one option.

CCS with EOR makes the economics look a little better. CCS with ethanol is really cool because you have already a carbon neutral fuel and now you're putting the carbon underground, so you're getting a double carbon reduction from that.

Definitely technically ready. I mean there's nothing we have to invent to do CCS. And I think that's really the primary message of the report. We need demos; we need early projects to try this. I mean, you know.

And we need to work on a few things. We need enabling frameworks for those early projects. We need to improve the economics of capture. We need to understand how to develop the infrastructure. And, again, that's primarily pipelines. We need to understand when you add CCS to your scenario analysis what happens to power costs and what happens to future energy portfolios for the state. We need to look at the ramifications of our different options for regulatory and statutory frameworks. And we need to get the technology plugged into the regulatory framework and develop appropriate protocols that fill the needs for CCS.

And, finally, if anyone has any questions, that's my email here at the Energy Commission and Kelly's. And another picture, again, no worries.

SUPERVISOR BOPP: Liz, a quick question on liability. Liability is a big issue. From what I've seen in other studies, as opposed to, say, a surface hazardous disposal site, is liability risk increases as time goes on, once it's closed.

What I've seen is that with carbon capture and sequestration, once that site is closed the liability, the risk drops off. So that, say, ten years after a site is closed, the liability is greatly reduced. Now, that's what I've seen.

Did you see that or not?

MS. BURTON: It depends. I can think of situations where that would certainly be true because your CO2 is stored more securely, as that graph tried to show. Over time, the CO2 isn't this phase that's trapped up against the cap rock. It's actually dissolving in the pore fluids and making minerals and so on. Reacting, going away.

On the other hand if you have a plume that's migrating offsite and your monitoring, you know, picks that up, then the risk for that site could go up.

SUPERVISOR BOPP: Good, thanks.

PRESIDING MEMBER PFANNENSTIEL: Other questions?

Thank you very much, Liz, that was very useful.

I think we're going to break now for lunch and come back to the technical panel. Let's start up again at 1:00.

(Whereupon, at 11:51 a.m., the workshop was adjourned, to reconvene at 1:00 p.m., this same day.)

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AFTERNOON SESSION

1:05 p.m.

PRESIDING MEMBER PFANNENSTIEL: Even as we're waiting to get the last person hooked up onto the webcast, I think we can begin the panel.

Would your preference be, Kelly, that we go down and have people introduce themselves, or was there going to be some other introduction?

MR. BIRKINSHAW: No, actually, --

PRESIDING MEMBER PFANNENSTIEL: How do you --

MR. BIRKINSHAW: -- Ms. Burton will be moderating this for us. I suggest that individually they --

PRESIDING MEMBER PFANNENSTIEL: Kelly, you need to be at a mike if the people on the phone are going to hear you.

MR. BIRKINSHAW: I've asked Liz to provide some moderation of this panel. But I'd suggest we get started and have each of the panelists introduce themselves and their area of interest, and their role in the whitepapers that were produced for this report.

PRESIDING MEMBER PFANNENSTIEL: Okay, great.

DR. MYER: I'm Larry Myer. And as I introduce --

PRESIDING MEMBER PFANNENSTIEL: Larry, make sure the green light on your mike is illuminated. Thank you.

DR. MYER: Larry Myer; I'm the Technical Director for the WESTCARB project, as I introduced myself this morning. And a little bit more background.

I've been a researcher for 20-odd years at Lawrence Berkeley National Lab in the earth sciences program. And my area of expertise is geophysics and geomechanics, which leads me then to think a lot about monitoring.

And that was why I talked about it a lot. And so I've done research in fields related to monitoring activities that we would encounter in sequestration.

MS. WADE: My name is Sarah Wade and I worked on the regulatory piece. My background is pretty diverse. I've done some work for state environmental agencies in Connecticut and Massachusetts on solid waste first; and then on air quality.

I've done quite a bit of work in climate change; and I've done some work in emissions trading for both NOx and SO2.

I've been working in sequestration since about 2001. And my major focus is public acceptance at large. What I mean by that is not just communicating with the public, but also thinking about how do you get regulations, public acceptance leading to support financially for projects like this. How do you actually demonstrate them and get permission, so to speak, from the public to build projects. What needs to be done to work with the regulators to get regulations in place. And things like that nature.

MR. FRIEDMANN: Hi, there. My name's Julio Friedmann. I'm at Lawrence Livermore National Laboratory, and my title there is the Leader of the Carbon Management Program.

We are chartered members of WESTCARB and work closely with the state and with Larry on a number of technical issues. Among other things, the program that we have deals with carbon capture technology development; with carbon sequestration science; and with unconventional and conventional hydrocarbon recovery.

I have worked for about 15 years in a combination of industry, government and academia positions. And in those roles I have contributed to, among other things, the MIT Future Coal Report, the National Petroleum Council's recent document, Facing Hard Truths; and a number of Department of Energy reports and documents and some 30-plus technical documents.

MR. PRICE: My name is Phil Price. I'm from Lawrence Berkeley National Laboratory. Just to clarify, it always gets confused. There are two similar-named labs, Lawrence Livermore National Laboratory and Lawrence Berkeley National Laboratory. I'm from LBNL. I sometimes tell people it stands for Lawrence Berkeley Not Livermore.

(Laughter.)

MR. PRICE: I'm in the Indoor Environment Department, and have been there for 15 years, I, and both of my co-authors on the risk and -- sorry, the risk analysis portion of the report.

I have some background in decisionmaking and risk analysis for indoor exposure to hazardous gases. And one of my colleagues has background in quantifying uncertainties in underground fluid flows, and another has extensive decision analysis and risk management background.

MR. MYHRE: Hi, I'm Rich Myhre. As I mentioned this morning I'm the designated generalist of the group. Unlike the others here, I was not an author of the whitepapers, the technical foundation documents.

But I am on the author team for the synthesis report.And the two areas of whitepapers are on CO2 capture technologies and economics. We are trying to get our capture whitepaper author in via phone; and the economics author is actually on travel in Europe at the moment.

I have background, general familiarity with those topics. I have an engineering background and I've done a lot of work with researchers in the power industry for a number of years. So I'm generally familiar and will do my best to answer questions.

MS. BURTON: I think I need to be at a mike, right? Which is going to make moderating this a bit challenging, but --

PRESIDING MEMBER PFANNENSTIEL: Would it be easier to use the mike over here? It's up to you.

MS. BURTON: Should I -- well, then I have my back to the audience, but --

PRESIDING MEMBER PFANNENSTIEL: Well, your choice.

MS. BURTON: I'll go back and forth so everyone's equally offended, I guess.

On the phone, or the person we're trying to get on the phone is Dale Simbeck from SFA Pacific, and he wrote the capture technologies whitepaper. Are you there, Dale? Not yet. Okay.

And I guess, Rich, you know probably more about his background than I do. Do you want to say a bit about how long he's been working on these issues.

MR. MYHRE: Oh, I couldn't say how long, but I can say that one thing that is just a broad generalization is Larry Myer showed this report earlier, this special assessment on carbon capture and storage from the Intergovernmental Panel on Climate Change.

That was truly a collection of the world's experts in this topic authoring that report. We're blessed in California to have many of those authors live and work in the state. And

Dale Simbeck of SFA Pacific is one of those authors.

MS. BURTON: We also have in the audience to chime in should there be relevant questions, John Clinkenbeard from the Geological Survey; in the back row Mike Stettner from Division of Oil and Gas; and for siting issues, Jim McKinney from the Energy Commission, if there are any issues about power plant siting. I think he agreed offline he'd be happy to address those.

I think if the Commissioners have any specific questions they'd like the panelists to address, I've put copies of kind of our guidance questions that we wanted to cover. But I'll let you guys have first crack.

PRESIDING MEMBER PFANNENSTIEL: Not at the moment. Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: I guess my principal question lies with the economic tables that you presented earlier that are table 11 and table 12 in the report, itself.

And the question is the extent to which these are first-generation cost numbers that could be assumed to come down with additional facilities installed, some type of experience curve and its impact on these costs, if any.

MR. MYHRE: Commissioner Geesman, I'll take a crack at answering that. Those tables were provided by Howard Herzog and his colleagues at the Massachusetts Institute of Technology. And in the field of sort of power system and CO2 capture cost economics, they will typically talk about the cost for a first-of-a-kind plan versus an nth-of-a-kind plan.

And so there will often be a cost premium put on by the engineering companies and the developers of a first-of-a-kind plan. So those cost tables do not reflect those first-of-a-kind costs, but they do reflect early applications.

And so over time, yes, through the combination of what's called learning-by-doing, and also improvements in the fundamental capture technologies, themselves. This is a hot area of research worldwide. And there is reason to be optimistic that the energy penalties and the operating costs, in particular, for some of these technologies, particularly post-combustion capture, will come down.

ASSOCIATE MEMBER GEESMAN: Well, I guess

my concern is that the dollars-per-metric-ton numbers are wildly in excess of any of the discussed attributed costs of carbon, or price of carbon associated with the cap-and-trade debate in this country, or proposals for carbon tax.

I had the privilege of listening to the Assistant Minister for the Environment from Germany last week make a presentation before financial analysts in London in which he said that Germany plans to have 12 carbon capture and sequestration facilities in operation by 2020.

And I'm trying to connect assertions like that or the presentation made earlier this morning with carbon prices that don't even begin to approach the costs that you folks have projected.

MR. FRIEDMANN: I could speak to that a little bit. The costs, which are shown for the tables in the presentations you were given there, are really for early applications.

For some technologies, for example if you were to do precombustion separation using Selexol, you can buy a very large commercial unit for that today. And that's a reasonably old technology. And people say that you can do that at $24 a ton. And that the price guarantees for various companies are prepared to put on that will back that up in some cases.

The cost for post-combustion capture is radically different. Those costs are likely to be substantially higher.

So what you're seeing instead is that if you were in the process of constructing a new plant, and you had a $30 carbon tax or cap-and-trade you would choose to build a different kind of plant, knowing what the price of carbon was. And that's the kind of analysis which the MIT folks regularly do.

And what they try to figure out is at what point do people make different decisions about what to construct. And at those points is where you see substantial action at the $30 level.

MR. MYHRE: I'll just add the European Union trading system had hit a high of 30-something Euros about two years ago. Not sure what the exchange rate was at that moment in time. But that showed that there would be perhaps at some point, you know, $40-a-ton carbon.

We would suggest essentially the deeper cuts that you wish to make in CO2 emissions naturally the costs for the last incremental emissions are going to increase.

But I think it would, as a general characterization, and I think that Liz tried to make this this morning, this deep cuts in greenhouse gas emissions is going to be expensive. And I think that's true in Germany and in California.

ASSOCIATE MEMBER GEESMAN: That being the case, and this entire subject area of capture and sequestration being put forward as a necessary element in international control strategy, ought we not to be approaching this less from a "how much cheese do I need to put in front of the mouse to get him to eat" and rather more toward the approach taken in the development of nuclear power, where collection for nuclear decommissioning was made a requisite part of a project's financing from day one?

MR. FRIEDMANN: There are many different policy mechanisms which people are investigating to discuss ways of bringing the costs into the system.

I would say upfront, first of all, that that's entirely outside of my purview to talk about. But there are certainly credible people who are looking at exactly those questions, as to what the right approach to internalize those costs are.

One of the things that I feel comfortable saying, though, is that on a rate basis, if you look at it in terms of cents-per-kilowatt-hour, commonly what people talk about is the delta price increase for cost of carbon capture and sequestration is on the order of -- well, it depends on which date the numbers are -- in today's numbers it's about 2 to 3 cents per kilowatt hour. In 2002 numbers it's about 1 to 2 cents per kilowatt hour.

And that those costs are entirely conformable with the delta cost for wind power and a delta cost for nuclear.

And members of the three communities that do this have agreed to say that those costs are close.

None of us feels comfortable saying, in most cases or even in all cases, that one will be a winner over the other.

But in terms of the necessary costs to bring these technologies into a substantial share of the market, you're looking at a similar kind of shared price of delivery. And that makes this technology comparable and attractive in the same ways.

How those costs are carried by different sectors is a completely different topic, though.

MR. MYHRE: And I'd like to add just one more comment, building on what Julio said. I think real-world decisions will go beyond simply the cost of CO2 avoided. He mentioned nuclear and wind, and CCS on fossil technologies may prove to be much more dispatchable than those technologies in terms of load following and other sorts of demands of managing the grid.

I'll also point out that those cost numbers are very broad estimates of a typical situation for a technology class. There's quite a bit of site-specific variation that you will see in those costs. And obviously, I mean you've got commercial entities coming forward today with projects that they believe are cost effective.

There's new technologies, we've got Clean Energy Systems here in the room. We don't actually have a line in the table for their oxy-combustion technology.

So, I'm not sure if I'm answering your question, but I'm trying to assure that we don't perhaps read too much into this broad class of costs, which was developed, I think, for the purpose of making broader societal policy decisions in terms of in general what sort of sources would we look to put this technology on first, rather than moving into the specifics of individual projects.

ASSOCIATE MEMBER GEESMAN: The concern I have is that these costs are wildly outside the parameters of today's existing political debate. Congressman Dingle, to my knowledge, is the only elected official who has ventured forth a suggestion of a $50-a-ton cost. He's framed it as a tax. And he's been widely criticized for being motivated more out of a desire to thwart efforts in this area than to promote them.

I think these numbers require a great deal of consideration and digestion because I don't think that most policymakers, outside a small technical elite, are really familiar with the magnitude of these numbers.

PRESIDING MEMBER PFANNENSTIEL: And I'd go a little further. I'm not sure that most policymakers can afford not to understand these numbers. They are going to be very important as we make some, draw some conclusions about what some options are in California.

And, yes, they're site-specific, and they're technology-specific, and they are source-specific. But we sort of know where we are in California relative to all of those. And so we need to have some numbers that we can use, not in a precise way, but in a relative way to guide us on some of the policy decisions we need to make.

So these become very important. I think that the discussion that was in the report is useful, but it's probably not nearly enough. And especially since, as Commissioner Geesman points out, the order of magnitude here is quite a bit higher than most of the conventional wisdom debate is about.

MR. FRIEDMANN: Let me add something to that. The kinds of analyses which you're requesting are currently, in part, being undertaken by National Energy Technology Lab. They are also currently, in part, being undertaken by a consortium of groups in California, most notably Stanford, UC Berkeley, Lawrence Berkeley National

Lab and Lawrence Livermore National Lab.

And some of that is being done with the support of the Commission; in which they are trying to get their hands on these numbers in some sensible way.

Just a factoid that helps orient the discussion, I think, is that the current federal subsidy for windpower is 2.1 cents per kilowatt hour. And that's certainly not outside the bounds of what we're talking about with respect to carbon capture and sequestration.

By the same token, you are absolutely correct to suggest that there isn't anybody who's suggesting that that cost be spread across the entire ratebase, which would be a very different kind of discussion.

But when you compare these technologies at their root they are comparable in many ways.

MS. WADE: I think there's also some other important points to consider in looking at this. One of the things is that with CCS, sequestration, you're talking about a long-term need, a long-term development of cost breakdowns or cost reductions.

And so what I think you should be

thinking about is how important is this technology going to be as you get to 80 percent reductions or things like that.

And so, like Mr. Dingle, right now with the $50 suggestion, there's also several proposals that are talking about 80 percent cuts at a national level by the 2050 timeframe.

It's expected that CCS is going to be pretty important for that. And the need to drive down the cost is going to be important. So investments today are going to help to do that.

I think if you look at, say, for example, the acid rain program, when that first started everyone thought the technologies for reducing SO2 would be out of the ballpark, as well. And they've dropped considerably as a result of the pressures of that marketplace.

And I think the expectation is that the cost of capture will likewise drop as you start having more and more of it happen. So, insuring that you've got cost effective reduction technologies available for the kind of scale of reduction that we're talking about, a few years down the line, it's going to be pretty important. And that's one of the factors for considering these costs right now.

The other thing that I'd like to point out is that with the NETL program I think the reductions are to bring down the cost by 35 to 40 percent, if I'm not mistaken?

MR. FRIEDMANN: It's the extent that -- sorry. The explicit goals of the NETL program are to have $20 a ton capture by 2010; and $10 a ton capture by 2020. And that is well within the bounds of what is reasonable on a thermodynamic and engineering basis.

ASSOCIATE MEMBER GEESMAN: So, three years from now these numbers, table 11, table 12, you feel will be technologically reasonable to substitute these with $20-per-ton figures?

MR. MYHRE: Personally, I would not go along with that. I believe that those $20 numbers were developed prior to the recent skyrocketing price in the cost of capital equipment for power generation. And this is affecting all power generation technologies. Coal, nuclear, wind, across the board, have seen an unprecedented increase in capital costs over the last three years.

And so it is very important to bear in

mind the point in time at which those goals were set.

So I think the cost reductions, three years, I'd like to see a little bit longer than three years before I gave you a forecast of price decreases. But it's going to be awhile, I think, before you get down to $20.

MS. BURTON: Dale, are you on the line?

MR. SIMBECK: Yes, I am.

MS. BURTON: Would you chime in?

MR. SIMBECK: Yes. I'm not sure who was talking, was that --

MR. MYHRE: Rich Myhre followed --

MS. BURTON: Julio, followed by Rich.

MR. SIMBECK: Okay. But I wanted to concur with what Julio said; I was just in Canada all last week, and they've put into effect either a $15-per-ton CO2 or a $20-per-ton, depending on if it's province or the federal government.

And the general consensus is that won't cause any CO2 reductions to speak of, with the high construction costs now, especially associated with CO2 capture and storage.

MS. BURTON: So, do you think it's reasonable to expect the technologies to advance on the timeframes that were outlined?

MR. SIMBECK: Yes. We had -- well, if we take action, we need both learning by doing and then advanced technologies, we need both. And it's very hard to predict which will give the greatest reductions. But there will definitely be reductions with time.

I think the important point is at the current time construction costs are quite high. And so that's hurting all these low carbon sources, including wind turbines. Their construction costs have greatly increased due to their steel use. And on CO2 capture, their costs have increased recently due to the much higher steel prices, in addition to construction costs.

MS. BURTON: Thanks, Dale. Shall we move on to -- okay. I think this question relates back somewhat to something that was brought up earlier. We talked about California's uniqueness versus what's going on in the world; and how many of the lessons learned from these other projects that are going on globally can actually be transferred to California versus what has to come from demonstration projects done instate. And I think that puts seismic right up there as maybe the first thing we want to tackle within that subset.

So, I know -- can I start in the middle -- Julio had some comments he wanted to make about that.

MR. FRIEDMANN: One of the things I didn't mention earlier is that actually I'm a sedimentologist -- geologist and geophysicist by training. And so this is something I actually know something about.

And in this area there are some things which we can pick up from other projects around the world and feel good about bringing back to the State of California, and feel very comfortable with them.

One of them Larry even touched on, which is the viability of various monitoring technologies, among them time-lapse seismic. There's also been pilots in which actually a number of the groups here at the table were involved, in south Texas, in the Frio Project, in which different monitoring technologies again were vetted and tested successfully.

Those kinds of learnings can be brought back to a place like California to some extent, given the uniqueness of our geology. Other projects like the one that bp is involved with is injecting CO2 at 7700 feet of depth into fairly low permeability reservoirs. The fact that we know that we can inject CO2 at that depth into low permeability reservoirs matters in terms of the California context.

There are a few things which we would really want to get our hands around in the state that matter quite a deal. One of them is the nature of these cenozoic marine basins, which as John had mentioned. Those include primarily Ventura, Los Angeles, San Joaquin and Sacramento Basin.

The good news is that the geology between those basins is similar in many ways. But the geology of those sedimentary units and the tectonism that created those basins is local. And you would want to get your hands on those to really understand the potential validity and safe and effective sequestration in the State of California.

One of the important ones, and Liz mentioned this, is also to think about the hazard associated with the seismicity. We have a lot of faults in California. Our maps are not faultless. And as a consequence we need to understand those hazards very well.

Also, as has been mentioned earlier, the presence of faults, including highly seismically active faults, in no way, shape or form suggest that California is unsuitable for carbon sequestration. We know that the crust holds buoyant fluids here. It has held buoyant fluids for tens of millions of years. And that has worked very very well.

Even large earthquakes have not spontaneously vented our hydrocarbon resource back to the surface because the crust has mass and the crust has strength.

Rather, we also know that there are sites in California where the faults act as seals. And there are other sites in California where they do the opposite. And so we actually have enough knowledge to a first order to look at a specific site and say, is this site going to store carbon dioxide well, or is it not.

And in the same context we can say is this fault likely to fail. What's the pressure change that would induce that failure. What would be the potential magnitude of a fault failing in terms of a seismic magnitude. What would be the operating pressures which would either induce or prevent that kind of action.

We actually have a great deal of knowledge from academic studies, from analogue industries, from specific attempts to create earthquakes in the past, any other number of things that we can use to frame thinking about the seismic hazards.

And the good news is that that information can be brought to bear at any given site. And that level of due diligence, I think, would be well advised for a project in California. But, again, it doesn't require a miracle; it requires some careful study.

ASSOCIATE MEMBER GEESMAN: So how would you frame such an analysis at a California site? What examples from analogous industries are there, what experience have we had either here or elsewhere in the world?

MR. FRIEDMANN: And this is specifically with respect to the seismic hazard question?

ASSOCIATE MEMBER GEESMAN: Yes. Specifically with respect to induced --

MR. FRIEDMANN: To induced seismicity. The State of Colorado is actually extraordinarily helpful in this context. The State of Colorado is where this whole geophysical line of investigation was born, at the Rocky Mountain Arsenal.

There were large volume injections of hazardous waste into very low permeability rocks, specifically ptygmatic gneisses that are 1.7 billion years old, at 3 kilometers depth.

Those created earthquakes that were directly correlated with the injection. And when they did, they were as large as magnitude 5.3. The discovery of this shut down the Rocky Mountain Arsenal's injection program, and rightly so.

The flip side of that was that got people thinking that they could induce and control earthquakes. So across the State of Colorado they tried to make as many earthquakes as they can.

They went to an oil field called Rangely. And at the Rangely oil field they began injecting huge volumes of water in the attempt to create earthquakes, because they wanted to prevent the big one. This was the geophysical notion of the day.

Despite their best efforts they were

unable to create an earthquake greater than magnitude 3.1. And the reason why was because those were permeable rocks, so you could never build up pressure, so you could never induce an earthquake.

Since that time that site has received 60 million tons of carbon dioxide for enhanced oil recovery. And monitoring programs have demonstrated that it has not leaked back to the surface.

So we can actually say quite a bit about what it takes to induce an earthquake in a potential storage site, looking at the State of Colorado.

MR. PRICE: I'll just state the obvious related to the question here about California-specific knowledge, what can we get from other places. And that is the capture technologies and the transport pipeline technologies, obviously will, you know, can use the same ones here.

And this does give me a chance to mention something that came up in your questioning earlier. I forget which one of you asked about TetraTech's assessment that the largest risks are from pipelines rather than from storage.

That's referring to risks to humans. Not risks of leakage back to the atmosphere. There you're quite right, the amount that can leak out of a pipeline is trivial compared to the amount that can leak back over the course of tens of thousands of years from the sequestration site.

But as far as risk to humans is concerned, if you want to get a risk to humans, you have to find some way to get carbon dioxide to the surface in concentrations of several percent at least, which it turns out is very hard to come up with scenarios to do that. But a pipeline break could do that.

ASSOCIATE MEMBER GEESMAN: Well, I think she had indicated that the real risk for the pipeline were trace gases, not the CO2.

MR. PRICE: The CO2 is also a risk for mostly an industrial worker kind of scenario. The carbon dioxide, not very dangerous, even if diluted to levels that -- many things we think of as toxic materials are far more dangerous than carbon dioxide.

But, you know, a few breaths of 20 percent carbon dioxide is enough to kill you. That really can't happen except for workers in those environments. But that is a risk to those people. It's a standard industrial risk.

ASSOCIATE MEMBER GEESMAN: And the primary characteristic there is a contained environment?

MR. PRICE: Yeah. If you -- yeah. Dilution from the atmosphere would rapidly dilute. You saw those photos of people standing under a geyser of carbon dioxide mixed with water.

MS. WADE: I'd also like to clarify that earlier when the reference was made to the environmental impact statements for FutureGen, those looked at the potential risks because some H2S, hydrogen sulfide is included in that expected carbon dioxide, they came up with relative risks.

And so relatively speaking the biggest risks of that project were related to risks associated with the action of the H2S in the subsurface, those were still considered to be minor risks overall. The project showed that there was very little risk associated with FutureGen. It's just that of the risk they found, those were the highest.

MS. BURTON: We actually have an author of that risk assessment for FutureGen, the primary author, in the audience, which is not -- and I think he would be agreeable to come up and say a few words about that.

ASSOCIATE MEMBER GEESMAN: Come on up.

MS. BURTON: This is Thomas Grieb, is that -- pronounce that --

MR. GRIEB: That's right.

MS. BURTON: -- correctly?

MR. GRIEB: Thanks. Yeah, I was the senior author for the TetraTech Group on that risk assessment. And I would like to clarify that it's not a TetraTech risk assessment. It is the official DOE risk assessment, which we served as a contractor.

The primary risk that we identified was with the pipeline activity. And for that we developed a database for all pipelines in the U.S. Looking at the frequency data, and then using a 50-year lifetime we projected probabilities of risk.

And the greatest risk occurred at one of the Texas sites. There were four sites evaluated. And the distance was 100 kilometers. And at 100 kilometers for 50 years the probability was .25 that there would be one rupture event.

And during that rupture event we modeled over the entire length of the pipeline what the potential risks were to individuals. And we predicted the number of people affected at what distance.

The risk was entirely to the H2S that's in the pipeline, that's removed during -- in the IGCC plant it's removed in one of the steps. And what makes the FutureGen project unique and different from the facilities that transport CO2 as the commodity used in EOR, is that the H2S that we analyzed was at 100 ppm. And the commercial operations, I believe, limit to 30 ppm of H2S. So we modeled at 100.

We also, you know, that's assuming that you -- that's a .01 percent H2S. We also modeled 2 percent, as well, which is the co-sequestration event.

And so those numbers are there and readily available. And I was going to make a comment later. I think that the state's report should address the H2S issue, which I don't think it does now.

ASSOCIATE MEMBER GEESMAN: As a feature of transport?

MR. GRIEB: Yes, in the pipeline.

SUPERVISOR BOPP: Could I ask just a clarification. I think I heard you say you come up with a .25 probable. Was that .25 percent or --

MR. GRIEB: No, no, --

SUPERVISOR BOPP: -- .25, okay.

MR. GRIEB: -- .25. It was a probability.

SUPERVISOR BOPP: Okay. That's pretty --

MR. GRIEB: Of a complete rupture. And it turns out I was in Texas for one of the public meetings; and in a nearby state on the news they broadcast such a rupture of a CO_2 pipeline. And I have the video, if you're interested.

MS. BURTON: Thanks, Tom.

MR. MYHRE: I'd like to just add for the record that for the largest instate source, natural gas combined cycle power plants, post-combustion CO_2 capture applied to those power plants would not have H_2S in the pipeline.

MR. FRIEDMANN: Or, for that matter, natural gas oxi-firing plants would also not have H_2S.

MR. GRIEB: I should clarify that FutureGen is an IGCC plant. It's quite --

ASSOCIATE MEMBER GEESMAN: You need to speak into the microphone or we won't get it on the record.

MR. GRIEB: The FutureGen plant is different. It's an IGCC plant, gasification, combined cycle plant. It's different from those -- I don't mean to indicate that it would be the same, you know.

MS. BURTON: I think we do have a small paragraph under monitoring and verification that brings up trace gases. But other than that, we've been a bit remiss in including that within the risk piece and so on. So, if that's deemed significant, we should think about that for the next go-round.

Larry, did you want to comment at all on seismic issues, in particular; or just more broadly on this issue? I think, to some extent, you addressed this question in your talk, but --

DR. MYER: Well, I did, so I wasn't clear that you needed to hear more about it. You know, we can certainly learn a great deal from other ongoing efforts around the world. And I'll give you a couple of specific instances.

I showed a picture from this experiment in the North Sea, the Sleipner experiment. And what this experiment showed, first of all, was a new understanding of how the CO_2 spread in the subsurface.

If you were to have seen the projections of how CO_2 would move in the subsurface before the Sleipner Project, you would have seen a scenario in which the CO_2 would go into the subsurface and immediately rise up to the nearest stopping point, and then spread out thinly.

And the Sleipner experience demonstrated the importance of somewhat minor, in geologic terms, layering within the formation which caused the CO_2 to spread out more. And this has a big impact, because it better spreads the CO_2 out in the reservoir than anyone would have thought. It changed everybody's perception about how the plume moves in the subsurface.

And so, you know, here's something that's going on in the North Sea which dramatically changed everybody's perception about how the CO_2 moves in the subsurface.

So, all of these, almost any test that

you do, if it's done well, provides a knowledge base that adds to our understanding about how to move forward.

SUPERVISOR BOPP: Larry, okay, so what you're saying is that you get more of an immediate horizontal displacement instead of a vertical?

DR. MYER: Yes, you get a much more, from the terms of -- in terms of capacity and storage effectiveness, if you will, the amount of CO2 stored per unit volume of the reservoir, if you've got some -- literally if you've got some heterogeneity in the reservoir and baffles, it spreads it out much more uniformly than in a very homogeneous reservoir.

You know, this is really fundamental to understanding sort of the size of the project that you need to build.

MS. BURTON: I'd like to give this same question a regulatory and statutory twist, because -- and this, to some extent, segues us into question four. We know a couple of states have come out with some studies recently about regulations. And so not so much the global perspective, but what's going on in other states with regard to regulations and statutes.

MS. WADE: There's a lot to be learned; there's also a good model to set. And so I'm not sure how you want to value those two different opportunities.

There's a couple different things to consider in this. Internationally, it's very interesting to start comparing what's going on in Europe with the U.S. And there's a number of different points that are very useful for consideration.

For example, in most of Europe and Canada the government owns the pore space. And so that puts a whole new dynamic on how you treat liability and property rights acquisition. And although it's not giving us an easy answer, it does give us some thoughts about benefit issues and justifications.

Likewise, the system over there is just not quite as litigious. So that also gives some interesting points of comparison that lead to some thoughts perhaps about how to develop policy.

I think that in California you are, from someone who was born here, but left early, I've always admired from afar how you start to tackle these issues in a very public way with a lot of discussion. And I think that that provides an opportunity to really air some issues that so far have been mostly within the realm of the technical scientists and the industries involved.

And so to air it more publicly, I think, is going to help create a more robust approach for taking on this topic from the regulatory perspective. I think it's also going to start to reveal issues that do need to be addressed that haven't even been discovered yet. So there's quite a big value there.

And I think the approach of taking it on as you are now is more of a study, if you will, and a gradual movement into it is going to be a better way of approaching it, in the sense that you can build experience and familiarity with the issue. You can also grapple with issues as they come up and identify them in a more gradual process instead of being confronted with them when there becomes more of a commercial deployment push.

And I think that's possible. Your citation of the nuclear industry push, for example, is one where I'd point to there being not a great deployment strategy. One that sort of backfired. And I think you're in a position now to avoid that. So, I'd suggest those are some of the values of out-of-state experience.

ASSOCIATE MEMBER GEESMAN: Haven't the oil and gas industries in many of the American states already blazed this trail quite a ways?

MS. WADE: I would say no. That's my personal opinion. I think that there's a discussion even today in a publication called "Carbon Control News" I think. There's a story that's headlined "Industry Wants EPA to Regulate This." And then it cites the IOGGC paper as being a push for state regulation.

There's a number of issues that need to be resolved that many people have very strong opinions, but I don't think those are all the people that needs to be consulted on resolving those issues.

ASSOCIATE MEMBER GEESMAN: What's different in terms of current regulation of use of CO2 in enhanced oil recovery?

MS. WADE: There is a number of different issues that are different. First of all, if you're looking at just the commercial application of enhanced oil recovery, you're looking at wells where because CO_2 has a value, in fact it's expensive, there's a big push to conserve it, recycle it as it comes up and possibly use it again.

And so you're creating situations at the moment for EOR where your purpose is not to store as much CO_2 as possible for long times, but, in fact, it's to use it to get that oil out and then move on to the next well.

So that's a fundamentally different approach than carbon capture and storage for climate purposes.

ASSOCIATE MEMBER GEESMAN: How's that change the regulatory perspective?

MS. WADE: Right now the regulatory perspective has not -- let me think about how to phrase this -- injection for enhanced oil recovery is governed under the UCS program under class II. The way that program is set up is that the EPA sets a federal standard protection, and then states can choose to seek primacy to implement that program on their own.

When the rule was created Congress decided to go ahead and accept all the wells that were already permitted under the Class II by regulation. And there was also a push to allow states to obtain primacy if the rules were fairly consistent, I would say, with the EPA rules.

The California rule is an example of that. In fact, in my opinion it's probably more protective than some of the federal rules. But it doesn't follow the federal rule exactly.

And so there's injection of several different liquids or fluids for enhanced oil recovery that are solely regulated for the purpose of recovering, not for storage. And the rule that govern those are going to be unique by state.

So that's sort of what's different right now. And I would also say the scale is going to be different. What we're talking about is stepping it up in orders of magnitude. In part because if you end up with a climate program that fosters sequestration, you will have more CO2 that's available at a cheaper price than it is right now.

So right now the cost of CO2 is one of the big limiting factors on this use of -- for EOR.

MR. PRICE: I'd also like to comment on this policy question a bit. I certainly don't have an opinion and no expertise in federal versus state regulation and so on, but I would like to say that whatever mechanisms are put into place for regulation I hope that they'll be flexible enough to allow change as we get more information. We're never going to know less than we know right at this moment. We're only going to get more information as we have more experience with these sites.

And that's going to change our assessment of what sites are or are not good. And I'm a little bit worried about the future, sort of public relations and political issues that that implies. If we have sites that are currently not being considered or judged unacceptable maybe because we just don't know enough about them. And then later we learn more about what makes a good site, and those sites become acceptable, from a technical standpoint that only makes sense.

But from a PR standpoint I worry that people will say, oh, you guys are, you know, make things weaker, less protected; you're allowing these, you know, formerly unacceptable sites to be used.

And so I do see some public relations

and political pitfalls maybe with having regulations that are flexible. But, I do think that we'll need to build in the capacity for change as we learn more.

ASSOCIATE MEMBER GEESMAN: Sounds like an argument, though, for going slow on generic approaches like statutes often have in preference to as much site specificity or project specificity as the state might be able to tolerate.

MR. PRICE: I guess I would -- I'm not sure, if I were in charge -- thank god I'm not in charge -- if I were in charge, I would be inclined to be pretty forgiving, pretty lenient, willing to certify sites as acceptable as long as there's no major chance of really substantial harm, if that makes sense.

And exactly how that's done or how that's determined, you know, we'd have to have a technical process to determine that. And then to plan on using that information to assess other sites. I realize that's a bit of a weasel answer, but I don't know exactly how that should be done and how generic those rules could be.

But I'm not sure I would put it in terms of generic versus nongeneric, as much as, you know, how bad are the consequences if things don't quite go like we expect.

ASSOCIATE MEMBER GEESMAN: If you've got, let me hypothesize, a handful of projects likely to be built in California over the next ten years, would it make more sense to empower someone, some agency, to make -- or to exercise a considerable amount of discretion on a site-by-site basis versus attempting to prescribe generic standards in state law that would apply to all such sites?

MR. PRICE: I think -- yes. To me the answer is yes. But you have to realize I come from a perspective that doesn't include a lot of the real-world political and PR issues that would come up.

Yeah, if it were me, I would say rather than try to specify in extreme detail kind of the Nuclear Regulatory Commission, you know, how do we certify a nuclear plant approach, we'll just specify every, you know, what kind of pipe you can use and how deep and how datadadada, and just try to get it all right and have one document that covers everything.

I would not take that approach if it

were me. I would think that a more flexible approach, and yes, with an agency empowered to make decisions with some discretion. I think that makes a lot of sense from a technical and learning perspective. Whether that can work politically, I don't know.

MS. WADE: If I can, the existing California rules governing injection wells in oil fields probably are sufficient, by and large, to go ahead and permit projects right now. And they provide a lot of room for discretion, for monitoring requirements, for contingency plans, for well integrity tests, for review of an area, things like that that would be exercised by the permit writer based on the considerations of a specific project.

So, arguably, that would be a very good model for going forward. It misses, right now, I think, on the long-term liability issue. So that's worth looking at carefully to see if there's a shorter term fix that doesn't lock you into something, but does provide enough cushion to move forward.

And I think that that's sort of a happy medium. It buys you enough time to look at a couple key areas where you may want to make some substantial changes for commercial deployment, but for the short term, on a case-by-case basis, you could use the existing framework.

The agency that implements that is not empowered to regulate CCS at the moment, carbon dioxide. They're focused on conservation and management of oil wells. They may need a slightly different mandate to handle that. They probably also would need resources that don't exist right now. And you need a process to insure that there's more of a public interplay on the permitting scale. But that's probably pretty do-able.

The issue, I think, is that if you want to start to go into saline formations for the experience and for understanding them, then you go over to EPA. And I think there's some significant issues of coordination that need to be thought about, and also consistency in the application of regulations. So that's possibly more of a short-term issue.

ASSOCIATE MEMBER GEESMAN: But is that the real threshold, it's when you go to the saline formations, as opposed to the enhanced oil reservoirs, using existing law and Daugger's existing authority.

MS. WADE: I think it is in California for a couple reasons. There's not a large number of class one wells the EPA has regulated. In fact, I think there's three that exist right now. And so there's just not as extensive experience right now with the saline formations.

You already have, in California law, you actually have laws that are specific to the specific oil fields because they know enough about those fields. So that's going to, by extension, suggest that you actually have a pretty steep knowledge base on the geology in those areas. So you can draw on that.

I do think there's another issue of does it make sense in the long term to try and have reservoirs managed from a state perspective, regardless of whether there's a federal class of rules for these wells.

And I think that the answer is probably going to be that you do want it handled at the state level just so that you can insure continuity in the long run in thinking about land use planning and other things like that that are going to be important.

ASSOCIATE MEMBER GEESMAN: And, in your judgment, is there a need in the enhanced oil recovery environment to address questions of long-term liability any time soon?

MS. WADE: I think there is. I think there's mixed responses to that, depending on the level of comfort with the reservoir, for example, and the interest of the company who's investing in the EOR.

My expectation is going to be that they are, in the long term, going to want some kind of coverage for --

ASSOCIATE MEMBER GEESMAN: There's no doubt of that --

MS. WADE: -- long-lived liability --

ASSOCIATE MEMBER GEESMAN: My question is from a public interest standpoint, is there a compelling need to address that long-term liability issue in the immediate future through legislation.

MS. WADE: Well, I come back to a simple equation on this. Enhanced oil recovery is a commercial enterprise in its own right. What we're really talking about is how do you extract carbon from large point sources of carbon that right now don't have any commercial interest in sequestering it.

And so ultimately this is about how do you get those sources to try and add these capture mechanisms. There's risk associated with that. And so until there are clear rules governing who actually owns the CO2 that's in the ground, and therefore who owns the liability, I think you're going to have the sources of CO2 say I'm not comfortable doing this because I can emit it right now with no liability. Once I put it into the ground it starts to become my CO2 underground and all these issues.

So, I think that you're going to find a desire to handle long-term liability on the part of CO2 sources. I think you're also going to see the injectors wanting to have that handled, as well.

ASSOCIATE MEMBER GEESMAN: In the short term can't they resolve that contractually?

MS. WADE: In the short term they might be able to resolve it on a couple key cases. But you're still going to have 100 years or long-lived potential liabilities. And not only do you have the liability that something may go wrong, but you're also going to have the liability that the regulations that ultimately come out are going to create a regulatory liability, as well.

MR. FRIEDMANN: If I could just add something quickly to this discussion. One of the questions is what's the purpose of the program, itself. The purpose of the program is strictly to get more oil out of the ground. And you're going to use CO2 to do it. Then that may not be necessary to them in the codes.

However, if the injection operator is also wanting to claim some sort of carbon credit for demonstrating it stays underground, then the current regulatory framework may not be sufficient. It may need to be reconsidered in some context.

What that actually looks like is open for discussion. But part of the reason why, as a community, we continue to talk about things like monitoring and verification, is around this question of crediting. And also the question of keeping the CO2 out of the atmosphere.

If those are part of the goals, then there needs to be some consideration for that.

Again, what that actually looks like is worthy of an extended debate.

Two other quick points on this. One of them is that one of the countries that Sarah didn't mention, but where a lot of action is happening now is in Australia. And they are actually amending their oil and gas codes in real time around this exact topic in exactly this way.

And I don't know that those regulations are out yet. But they are expected to be out shortly and approved by Parliament.

Another --

ASSOCIATE MEMBER GEESMAN: And why are they doing that? Are they contemplating going forward with CCS projects?

MR. FRIEDMANN: Not only are they contemplating it, they are actually building a zero emission power plant called ZeroGen, which is supposed to come online next year. I think it's probably going to come online in 2010 instead because of conventional delays, but they are going for that.

Another thing is that they are very very keen to develop export technology around carbon capture and sequestration, and seeing this as a way to incentivize it.

And early policy action in Australia was to create a $500 million matching fund program around large projects. That was done after their geological survey was able to validate the volume and rate of injection for the nation, as a whole. And that gave policymakers the comfort that this was a viable carbon management strategy for Australia.

ASSOCIATE MEMBER GEESMAN: And is the ZeroGen a plant, a coal-fired plant or a gas-fire plant?

MR. FRIEDMANN: It will be using brown coal, sub-bituminous coal, in Queensland, Australia. And they will put all of the carbon dioxide underground. Some fraction of it, I believe, is going into a CO2 EOR project, but I believe a lot of the CO2 is going into a saline formation.

ASSOCIATE MEMBER GEESMAN: And is that located near the plant? Or is there a transport requirement, as well?

MR. FRIEDMANN: I would need to follow up with you on that, about the specifics of the siting of the plant and the transport.

MR. MYHRE: They are -- I believe there will be a pipeline for the saline formation injection.

ASSOCIATE MEMBER GEESMAN: Any idea of how long?

MR. MYHRE: I'm going from memory and the number that sticks in my mind is 140. So presumably that would be kilometers because it was in Australia, but it may be the conversion figure that I'm remembering. That information is readily available for follow up verification.

MR. FRIEDMANN: You've reminded me of another project, though. They are building a large coal-to-liquids plant in Melbourne, Australia. Large is, I think, 50,000 barrels a day.

That plant will emit between 9 and 13 million tons of carbon dioxide. And they are building 110-kilometer pipeline onshore, 110-kilometer pipeline offshore, and are planning to inject that CO2 both into saline aquifers and into oil and gas fields offshore. And they are doing that entirely as a carbon management activity. Although they certainly are selling the oil -- the CO2 to the oil producers. That work is being done and it's being paid and being permitted in the carbon management rubric.

PRESIDING MEMBER PFANNENSTIEL: You mentioned a matching fund. Where is that coming from?

MR. FRIEDMANN: That was, again, put together by the Parliament. And they said any project which is capable of managing 2 percent of Australia's carbon dioxide emissions on an annual basis qualifies.

And --

PRESIDING MEMBER PFANNENSTIEL: So it's just taxpayer money that they're putting into a fund?

MR. FRIEDMANN: Right. It's just matching money for large projects. And they also, I think, even though this was being driven by a carbon management perspective, they also said this can be any kind of project. You want this to be a geothermal project, great. You want this to be a wind project, great.

But it helped to create a level playing field in the public interest around carbon management. And a number of projects, including a geothermal, including a wind project, but a couple of the carbon dioxide management projects have applied to that fund.

One last thought relative to your first question, Commissioner Geesman, which is about the need to go slow with respect to regulations. Another way to consider that is it's a need to go fast on large projects and saline aquifers.

That there's a public benefit to trying to understand that play fairly quickly. And if we are going to want to have technically sound regulatory doctrines then it's very helpful to have as much information as you can from these initial projects early on.

MR. MYHRE: I wanted to amplify that point. This morning we talked a little bit about these sort of low-hanging fruit industrial applications where you could proceed with a relatively favorable economics because the cost of capture would be much lower.

From what we heard a minute ago, too, your risk is going to be minimized and so will your costs, and so will the time of developing your project if you can actually inject onsite, straight down.

And in the central valley there are a

large number of those sites, but the underlying target formation would be a saline formation rather than a depleted oil and gas reservoir.

So I would suggest that it's worth also starting down the path of exploring regulatory procedures for saline formation injection.

SUPERVISOR BOPP: Okay, Julio, when you talk about moving fast on a large-scale saline injection project, I assume that would include actually on-the-ground, sort of an incremental approach where you'd be testing injectivity and monitoring and things like that.

MR. FRIEDMANN: Yes, absolutely. And I thank you for allowing me the opportunity to talk about that.

The devil's in the details around the site. It's incumbent upon anyone considering injecting CO2 in the subsurface to do it very careful and diligent site characterization effort.

That effort, in itself, is likely to take two to three years. However, the results of that work would also inform the consideration of some sort of standard for site characterization. It wouldn't necessarily be sufficient, but it would be a lot more information in the state than we currently have around that kind of a topic.

Similarly, once the site got a good green light and they could start injecting, there would need to be baseline monitoring before the injection. That would be information which you would need to be able to demonstrate the location and the constancy and the composition and the state of the CO2 in the subsurface.

That information, again, would inform the way that we think about the monitoring policies and frameworks. And all of that would be in anticipation of the actual first injection.

One of the things that that kind of staged approach also lets you do is it also provides you the opportunity that should you recognize that your initial site's not a particularly promising one, then you can reconsider.

And one of the things that, again, has been instructive from other parts of the world is in Australia they actually did that. They actually found a site where they were going to take CO2 out of the CO2 well, from natural CO2 supply, ship it a couple of kilometers over, and inject straight down.

And when they did that site assessment work they discovered that that initial site was not very well suited. And their solution to that was they assessed a neighboring site. They found that that site was well suited, and they repositioned their project.

So everything went forward. And, again, that sort of validates the kinds of learnings that we can bring from other locations. hey were able to show that that site assessment methodology was credible and it helped advise them around infrastructural operational decisions.

ASSOCIATE MEMBER GEESMAN: To what extent, particularly in terms of scale, can we learn from some of these other efforts around the world? Can we skip over a couple of the smaller scale demonstrations in preference for a larger one based on knowledge gained from other projects?

MR. FRIEDMANN: I think that the purpose of those projects is somewhat different. The purpose of the small pilot is different than the purpose of a large commercial project.

I don't think of those as either/or kind of things. And, you know, granted I have the luxury of a technical investigator to say that kind of thing.

But part of the purpose of a pilot is to vet the suitability of a site. But, importance of a large project is to provide operators and decisionmakers with the information that they need to know at scale. And there's simply no substitute for the scale projects.

And because of the local nature of hazards, the -- to stress, the location of wells, population centers, groundwater concerns, individual faults, all of these things are local. You need to understand how those projects will roll forward at the site, and a large project is crucial to that.

But the small project provides you a great deal of information on the potential suitability of an area, on the validity of monitoring technology. And one of the things that WESTCARB has done spectacularly well, I believe, is the actual steps that you need to go through to get a project off the ground.

And we've learned a tremendous amount in the past couple of years by pursuing these small projects in different regulatory settings, in different sites and different targets. And that's been a hugely valuable exercise that I would not want to forego.

DR. MYER: I'll just add a small amount to this. You have to appreciate that these large projects cost a lot of money, and therefore you're going to do fewer of them.

Whereas you can do more of these small projects. And so you have to balance what you can learn from multiple numbers of these small ones versus a couple of these big ones.

And you can learn a lot from a number of these small ones. I'm a strong advocate of doing as many as we possibly can of these small ones. And this has all to do with the, not only the geologic variability, but the regulatory variability that we have. The issues at sort of a local basis are very variable around the United States. So, it's very valuable to do as many of these small ones to sort of test the waters in lots of different areas.

Then you do a few of these big ones. But cost is a factor in deciding how you do these things.

ASSOCIATE MEMBER GEESMAN: Don't you think policy is more likely to be driven by carbon capture and sequestration than your research desire to experiment with a lot of small projects? And might we not have nationally the luxury of the amount of time required to pursue the large portfolio of smaller projects that you guys are talking about?

MR. FRIEDMANN: I couldn't disagree more strongly, actually. A couple of things. First of all, many different writers have talked about carbon capture and sequestration as a sine qua non technology. And that we are rapidly approaching the bifurcation point in terms of whether this technology is a option or not. If you don't have it in the carbon management portfolio then you need new energy backbone. And that actually is affecting commercial decisions in real time today.

The Department of Energy has actually accelerated its projects at the request of Congress, at the request of O&M, at the behest of many many companies, NGOs and actors because they want to get the handle on this costing just as soon as possible.

And, in fact, as a consequence, the phase three projects, which WESTCARB is beginning as of today, I believe, this is the first day of fiscal '08, but that is a two-year acceleration over the initial scheme.

And, in part, this reflects the urgency that people feel around this issue.

I would add to that that there have been, what is it -- let me just say it this way -- as an expert in the field, I feel like this question, can you do carbon sequestration at scale is the central question to a decarbonized energy strategy. There isn't another one. If you can't do this, you have to radically reconsider what is possible for your state, for your region and for your country.

ASSOCIATE MEMBER GEESMAN: So let me repeat, doesn't that drive you toward the larger projects? And sooner rather than later.

DR. MYER: It does drive you towards the larger projects. And we need to do more larger projects, as well.

I thought you mentioned capture, however. The issue with focusing on the subsurface is associated with the uncertainties in dealing with the subsurface. We can characterize carbon sequestration as, on one hand, the cost issues driven by capture. And that's a engineering technology issue. And a lot of sweat going into that. Those costs will come down.

And then the other side of this is the subsurface issue where it is the uncertainties and the sense that we need to convince people that we can do this safely and securely in the subsurface. And that is going to require going to lots of places and dealing with the particular issues associated not just geologic, but regulatory and, as far as that goes, societal issues in the particular locations, and dealing with them on that basis.

ASSOCIATE MEMBER GEESMAN: Well, I guess I combine the two or link the two because I think if you're headed toward large projects sooner rather than later, it creates more of a link to the need to co-locate with your point sources. Or at least to be in very close proximity to your point sources.

And that's where I'm not certain that the proliferation of potential projects in an environment like California is as compelling as in locations where you clearly have some very large point sources.

And I'm struggling to try and determine

where California sites fit into a national or international strategy. I'm willing to believe we have the best researchers in the world, but I'm not certain that we ought to be working on natural-gas fired projects, or putative prospective ethanol plants rather than coal plants, perhaps supported by California utilities, elsewhere in the west.

But it seems to me that it's like Willie Sutton, why do you rob banks? That's where the money was. Why do you go to coal plants? That's where the carbon is.

MR. MYHRE: Commissioner, it is true that at a single plant some of the large coal-fired power plants in the states to the east of us have more emissions per plant than do even the largest natural gas combined cycle plants in California.

Those plants are almost all multiply owned by load-serving entities, some of which are California-based, some of which aren't. Through WESTCARB we are working with our organizations in Arizona, Nevada and the states up in the Pacific Northwest, all the way to Alaska, on some of these issues.

And it may well be that you ultimately, in the calculus of things, maybe a project there goes first commercially. I think we've at least seen, though, that in one instance there's a proposer here in the room of a project using what I'll call California coal. Again, where sort of the -- there's an alignment, and this is obviously the Carson project I'm referring to, where you can avoid new transmission lines and a whole host of other issues that make -- I think there's going to be a diversity of winning projects. Some will be instate. And some will be out of state.

ASSOCIATE MEMBER GEESMAN: So should we have a petroleum-coke-focused program? Or refinery-centric program?

MR. FRIEDMANN: I think it may not be unreasonable to consider those as important pieces that are unique to California. But in the same way California has baseload natural gas plants. That's almost unheard of anywhere else in the country. Well, that's a real substantial carbon supply to the state. And to hit the Governor's targets, those sites have to be considered.

ASSOCIATE MEMBER GEESMAN: They were designed as baseload, but none of them operate 85 percent of the time that the assumptions in the study suggested that they will. And they're subject to market conditions that at least in recent years have driven those capacity factors down.

Seems to me that if you're trying to put a project together you want to insulate yourself as much as possible from those kinds of market or operational risks.

Refineries operate 24/7.

MR. FRIEDMANN: And they make a lot of CO_2 and they're worthy of consideration, as are the cement plants. In fact, I've been harping about cement plants for a long time, because if we end up offshoring the cement plants, actually, the emissions come back to us, plus the emissions from the shipping of the cement. And we lose the jobs in California. It's a triple loss.

But I don't think at this point you necessarily want to start taking things off the table. I don't think at this point you want to be saying, well, gosh, we really don't want to look at zero emission gas plants.

The nation of Norway is entirely about zero emission natural gas plants. In fact, the government shifted on that exact topic.

And we actually have somebody instate who makes the zero emission natural gas plants as an export technology. It may be that that's a solution which suits the states very well.

But until those analyses have been sort of done in some substantive way, I would be reluctant to declare those are of low value, when they are still an important component, you know, out of the 47 million tons of point source emissions. A lot of those are from the natural gas sector, and you don't want to necessarily say well, those are just outside of consideration.

ASSOCIATE MEMBER GEESMAN: Yeah, but with a finite budget you need to prioritize. You can't do everything.

MR. FRIEDMANN: I don't disagree with that at all.

MR. MYHRE: From the research perspective the subsurface research is relatively indifferent to whether the source of the CO2 is a refinery, a natural gas combined cycle plant, or a petroleum coke-fired gasification plant, a new ethanol plant, a cellulosic -- I mean it's the same subsurface regulatory issues that need to be addressed. Same subsurface monitoring technologies. Same subsurface modeling techniques.

And so if you look at within WESTCARB where is the bulk of the money going, it's on subsurface research.

MS. BURTON: I think if --

MR. PRICE: I have one more thing. Not my area at all so I should keep my mouth shut, but directly above my office on the fourth floor there is a group that works with carbon trading, international carbon trading.

And one of the problems that they wrestle with all the time is groups wanting to get credit for stuff that would have happened anyway. Or, you know, various -- there's just a lot of problems when carbon trading -- or carbon reduction is motivated by one regulatory regime and is passed over to another country or another, you know, state. What are the implications if we start insisting that other states do these things that maybe they would have been otherwise forced to do anyway.

As I say, not my area, but I just mention that it's not always so simple that you say, oh, well, we're making them do it, so we should get some credit for it. Doesn't always work that way.

ASSOCIATE MEMBER GEESMAN: Yeah, to clarify, when I say we're making them do it, or t use those words which were yours, I think the focus would be on our regulated utilities, not on some other state. The emphasis would be on those regulatees which theoretically, anyway, respond to our direction.

MR. PRICE: Yeah, I understand that, and at the risk of saying something completely ridiculous because I really don't know much about this field, you know, what if Arizona is also contemplating these programs and is, you know, is there an interaction between the fact that they are trying to come up with their own regulations, incentives, or whatever --

ASSOCIATE MEMBER GEESMAN: Six western states, two Canadian provinces are all in the same western climate initiative.

MR. PRICE: Yeah, so, I mean maybe this gets back to your question should these things be decided, regulated, motivated or incented at the national level or regional level rather than the state level. Not something I know much about, but I'm saying that it's not obvious to me that whatever we do based on California-regulated utilities, actually should count as a credit. You know, all of that being due to our action, and you know, we should feel good about it, if I could put it that way.

MS. BURTON: I think that there's maybe another piece to this, too, if I'm following your logic here. And that's we went to natural gas plants instate historically because they're cleaner. And we wanted clean energy.

Now, all of a sudden we have coal plants out of stat that are doing carbon capture and storage to meet our emissions requirements. They're cleaner than our instate natural gas plants. And does this suddenly evolve into California building new power plants that are coal-based in the state.

ASSOCIATE MEMBER GEESMAN: If you want to make that bet, I'll take it.

MS. BURTON: Well, I don't know.

(Laughter.)

MS. BURTON: But, you know, I mean I'm just connecting the dots here.

ASSOCIATE MEMBER GEESMAN: I think from --

MS. BURTON: You know, and then, yeah, you need those big projects in California if we're going down that road.

ASSOCIATE MEMBER GEESMAN: I think that my point there, Liz, was trying to look at the likely economics of a CCS project. In my mind, a coal plant is much more likely to operate at a very high capacity factor than is a natural gas plant. Particularly a natural gas plant in California.

MS. BURTON: That's correct, yeah. I'm just kind of wondering where that leads us in terms of the energy future for the state. And I know nothing about that, so I guess I'm kind of lobbing the question over the podium here.

ASSOCIATE MEMBER GEESMAN: Well, I think at $50 to $90 a ton --

MS. BURTON: No answer required.

ASSOCIATE MEMBER GEESMAN: -- there are a lot of people who have different opinions on that.

MS. BURTON: Yeah. But, you know, if that's on the table at all, then it makes the case very solidly for doing CCS research in the state.

So, anyway, not supposed to put my two cents in here.

Shall we move on? We've got, I think, about 15 minutes left. We started a little bit late, so I'd like to just take this until about 2:30 and then we'll open it up for public comments.

What should we do next? What are the most important things to do? Should we start with Rich, kind of each take about two minutes. General, as well as in your field.

MR. MYHRE: I think we should start at the other end.

(Laughter.)

DR. MYER: We've been batting around these ideas since the beginning of the discussion. So I'm going to share a view from the trench, in a sense.

It seems to me that some of the legal issues are extremely important to tackle right away. That there is enough ambiguity over pore ownership when we're talking about sequestration, and ambiguity over how mineral rights and pore ownership is going to be determined, that we need to sort this out first of all.

And then from that I think follows naturally the other regulatory issues that sort of follow from that. And then beyond that, the need for hands-on practical data from the pilot tests.

MS. WADE: I guess I'd add to that, as opposed to subtract from that. And I think that I always look at how do you put this into the context of a program. And so it strikes me that what you may want to think about is creating a dedicated goal of getting some research projects up.

Some of them should be large, some of them should be small. You've got WESTCARB already; you've got some private proposals. Perhaps those could be moved into it.

I think that if you're going to get that kind of research, you think about how you support it and also what do you get from it, if you're supporting it at all.

And so creating a set of priority issues to resolve to further develop the regulations, I think, for example, would be a useful thing to do. and also in dealing with the liability, which we haven't talked about much today, but there are a lot of ways that I think you could start to address this liability so that you insure you've got a long-term source of funding to take care of these activities that we expect you're going to have to take care of.

And that also could start to fund remediation if you end up having an event that you didn't plan for one of those projects.

And so there's some ways that you could start to take a look at shaping that so that you can actually see how that works.

And so in my mind the three legs of this, if you will, ar getting the projects going, but also thinking about what are you going to get from the projects from a research and regulatory development perspective; and also what kind of public support mechanisms do you need to think about developing in the long term, so that you might see more of this as it proves out.

MR. FRIEDMANN: I have four priorities that are four words each. First, assess California's geological resource. We simply have to expand on the existing work that WESTCARB and the California Geological Survey have done to assess the sequestration resource in the state.

They are going great guns. It's an outstanding team, but they just need more help and more support to do that.

Second, California-specific capture technology. We need to think about portfolio point source emissions in the state, and if we actually need to have a separate capture technology program that helps target whether it's refineries or cement plants, or whatever. What is unique about those thins from an engineering integration perspective, from a balance of plant perspective, from a cost perspective, to actually get these things to operate.

The third, south California large projects. I think we need to accelerate the large projects that are going forward in southern California, WESTCARB, bp, Carson and other ones, because that's where the greatest sequestration resource appears to be, and is close to important load centers, and therefore it's an important thing to consider.

And the fourth is develop standards and protocols, using the information from those other three projects, to think about what the state needs to starts to create in terms of regulatory environment.

MR. PRICE: To some extent that's sort of a blindman-and-the-elephant thing here. Each of us has their own perspectives. But I can tell, even from my fairly narrow one, that we're all sensing the same animal because I really agree with all of these comments that -- I'm relatively new to carbon sequestration as a topic, but I have a fairly large risk decision analysis experience.

And to me, when I first got involved with this issue I was, I have to say, a little skeptical from maybe the way that a typical uninformed member of the public is. It just smacked of desperation to be trying to pump stuff underground and keep it there for, you know, millions of years. It's like, my god, what are we doing.

But having learned more about it, it's totally do-able. The problems that I see, there are some problems on the risk side, but standard risk management approaches can deal with them, can assess them, and can mitigate consequences.

We can learn more and do adaptive management kinds of techniques with our, actually adaptively managing our regulatory framework.

I really see most of the problems being on the defining that regulatory framework so that it's flexible enough and yet protective enough.

And also on the communication with the public, the risk communication side, so that the public understands what are the risks and benefits. And what, you know, can help to define what is and isn't acceptable.

So, I guess I'm echoing the general consensus that it would be good to start solidifying some kind of regulatory legal framework soon so we can just get started.

MR. MYHRE: I guess I'd like to start by saying that even at the costs cited in the report most studies that I see that project out the path to achieving the greenhouse gas emissions reductions needed to stabilize CO_2 in the atmosphere at an acceptable level, show large portions of carbon capture and sequestration.

We may get to 2020 the goal without this technology having played a major contributing role, but there is a long lead time in the development of this technology and the associated legal and statutory issues. And I think it will behoove us in the long run to start that process now, and to make these technologies available, and bring that cost down at the point in time when we sort of plateaued out on some other alternatives. And this will probably be one of the primary means by which we bring emissions reductions down to that 50, 60, 70, 80 percent below 1990's level point.

And it seems to me that the policy direction worldwide is heading in that direction for a long-term goal.

I guess I'll add that I've heard the public education, public engagement mentioned a couple of times. That's one of my other roles in WESTCARB. I think we're again early in the process here.

Liz talked about asking her kid's karate teacher. I have the strange habit of asking people when waiting in line to catch a plane at airports what they know about carbon sequestration. And even climate change, and, you know, global warming in general.

And so I think there's a big job ahead of us. I want to thank everyone who's here today. And maybe when we have this hearing in two years for the next IEPR, we've got twice as many people in the room. That would be, you know, a step towards success in my mind.

MS. BURTON: Dale, are you still there? Or are you --

MR. SIMBECK: Yes. I've been quiet because I'm really filling in for the MIT people that did the cost estimates of the study. Their numbers do show this large range. And I tend to agree with the numbers.

Passing on what came up the last few weeks on work I've been doing in Canada for the joint venture of the Canadian Government and the industrial sectors, the lowest cost we came up with were a coke-based polygeneration where they were using the steam and cogen for heavy oil production, as well as captured the CO2 in making hydrogen for the upgrading of their oil systems.

Whereas the highest costs were just central power plants, stand alone by themselves, with and without CO2 capture.

MS. BURTON: I guess now I'd like to open it up if there's any specific questions that anyone in the audience has for our panelists.

PRESIDING MEMBER PFANNENSTIEL: Liz, I have a single blue card; somebody that has asked to make comment. I don't know if there are other people who would like to come up. But we can start with Michaeleen Mason from WSPA.

MS. MASON: Good afternoon, Madam Chair, and Members of the Commission. My name is Michaeleen Mason and I am Director of Statewide Regulatory Issues for Western States Petroleum Association.

I am pleased to offer WSPA's comments and perspectives on the role carbon capture and sequestration can play in helping California achieve the goals established by AB-32.

WSPA agrees with the IPCC that in appropriately selected and managed geological reservoirs CO2 can effectively be stored for a significant period of time.

WSPA also agrees with the intent of Mr. Blakeslee's bill that the State of California must look at ways to accelerate the adoption of cost effective geologic sequestration strategies for the long-term management of industrial carbon dioxide.

WSPA believes that carbon capture and storage can be a key piece of California's program to reduce carbon emissions. This report can be a significant first step to making that happen. WSPA will be providing detailed written comments, but we want to highlight a few items that we believe deserve special consideration.

First, the site identification and characterization process should balance data and information needs with economic and technological limitations. Storage site assessment and certification should be based on application of established modeling practices.

Monitoring techniques should be site-specific and used to demonstrate achievement of performance-based criteria for operational phase safety and secure long-term containment.

Economic viability of projects is essential. In view of the anticipated magnitude of investment required for large-scale implementation of CCS a stable and reasonably predictable economic basis for greenhouse gas mitigation is necessary.

Key to economic viability is legal and regulatory certainty. Legal and regulatory clarity and stability are needed to advance CCS in California.

Finally, we believe that CCS in enhanced oil recovery in California can be a very effective way to move CCS forward. Carbon dioxide for EOR is proven technology with a successful operating track record for more than 30 years. Using the existent regulatory scheme for EOR will allow the early removal of carbon dioxide from the atmosphere.

In summary, WSPA believes that the most effective way to move CCS forward is through a regulatory program that is based on sound site selection and certification process with a well-designed and implemented monitoring program, tailored to site-specific conditions.

WSPA further believes that legal and regulatory requirements should be performance-based. This will provide the flexibility to fit site-specific requirements and be adaptable for the rapid evolution of technology that is likely to occur during the early stages of implementing CCS.

Thank you for considering our comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MS. MASON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Bob

Lucas.

MR. LUCAS: Thank you very much. My name is Bob Lucas; I'm here today representing the California Council for Environmental and Economic Balance, also known as CCEEB.

We'd like to congratulate the Commission for putting together such a comprehensive report on CCS in such a short timeframe. The report has been supported by some of the most respected CCS experts, and we believe that the information will be helpful to the Legislature as they craft a path forward on CCS.

As we put the report in the context of AB-32 and the Governor's executive order of greenhouse gas reduction goals, we need to recognize the critical nature of CCS in assisting the state in meeting its emission reduction goals.

While it's not a magic bullet it has the potential to meet emission reduction demands of the state, while at the same time allowing the state to meet its energy demands.

We believe it's imperative for the Energy Commission and the Legislature to work together to insure that California remains the leader in technology, including CCS.

We recommend that the Energy Commission communicate the need for additional demonstration projects, both private and public, to help understand the technical and regulatory needs to shape the path forward in the long term.

Also, in the interim, the Energy Commission should work with its legislative partners to learn more about other projects that are underway globally, as well as review existing models for regulatory programs.

Thank you for this opportunity to express our perspective.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Mark Nelson from Edison.

MR. NELSON: Good afternoon; I'm Mark Nelson; I'm Director of Generation Planning and Strategy from Southern California Edison.

Wanted to make sure that everybody understood just how large of an undertaking this is. It's a very large report. It's been done very well, and very much would like to see the whitepapers, as well, because I know there's a lot of information that undoubtedly had to get cut out. But, again, you know, it is a monumental undertaking.

I've been involved in coal gasification since the early '80s, and it's been around a long time. Sequestration obviously is a new and more complicated facet that will also ultimately be a challenge that we'll overcome, as well.

I wanted to make sure that everyone was aware that Edison fully supports coal gasification and sequestration, and that we have a pending application at the PUC for a clean hydrogen power generation facility. Which, because we're a knowledgeable room, is a coal-based hydrogen generation project with sequestration that would then be -- the hydrogen would then be burned through hydrogen turbines. So essentially it's a hydrogen IGCC with sequestration.

Recognizing that it is fairly complex we are looking for funding right now with an application at the PUC for a feasibility study that has really four large components.

The first component is the conceptual engineering, because again you have to have an understanding of what the specific plant is, given the fuel sources.

The second part is the sequestration; the part that we've talked about here today for a full day that you've worked on for months. Because, again, we realize that we need sequestration targets. And the targets need to be both EOR for economics, but also there need to be geologic sequestration backup. Because if the EOR market, you know, falls apart, or if EOR is not sequestration, which is possible, as well. Because again there are regulations there.

So we're again assuring that we have, you know, as we plan the project both EOR and geologic sequestration.

The third component is a permitting assessment. Because we also agree and understand that the regulatory framework and the permitting is going to be very complex on any first-of-a-kind or even second-of-a-kind, third-of-a-kind plant.

So, as part of this feasibility study, we need to conduct a full assessment of permitting.

And then the fourth part is to make sure that in the event that the feasibility study points toward a plant that, in fact, is feasible, that we have appropriate options in place for right-of-way and land options and sequestration targets.

And, again, we don't necessarily all

understand what our obligation is with respect to a carbon plume that may be injected into a deep saline aquifer.

So, again, we see it as very challenging, but that said, Edison is moving forward at the PUC right now in an attempt to fund a feasibility study so that we can get the ball moving and do what we've all been talking about here today, which is to learn by doing.

ASSOCIATE MEMBER GEESMAN: Is your project likely to be within your service territory?

MR. NELSON: It's unknown at this time. The range of areas that we're studying would be the southwest, so it's essentially the footprint of southern WESTCARB and most of southwest CARB.

ASSOCIATE MEMBER GEESMAN: But you haven't ruled out southern California?

MR. NELSON: Coal-by-rail really is something you have to weigh off in the larger model against electricity by wire, if you will. So we have not ruled it out.

ASSOCIATE MEMBER GEESMAN: So are you still considering it?

MR. NELSON: I'm sorry?

ASSOCIATE MEMBER GEESMAN: Are you still considering southern California as a prospective site?

MR. NELSON: California is still within the model.

Thank you very much for all your hard work.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Tiffany Rau.

MS. RAU: Thank you. This is the first time I've ever had to wear glasses to read something out load, so --

I'm Tiffany Rau and I'm here today on behalf of Hydrogen Energy. It's a joint venture between bp Alternative Energy and Rio Tinto. It was formed earlier this year to pursue the development of commercial-scale, hydrogen-fired electricity generation with carbon capture and storage throughout the world.

We are also joint owners of the Carson Hydrogen Power Project, the only project yet announced in California, inside California, intending to build an IGCC power plant with carbon capture and storage. Be creating hydrogen from petroleum coke.

If successfully permitted and built CHP would remove over 4.5 million tons of CO2 per year that is currently being vented via pet coke emissions. And would inject it in declining oil fields for EOR and long-term storage.

If we are successful CHP would be the single most significant reduction in GHG emissions from a California source ever. And it could pave the way for further projects to provide the next generation of baseload, low carbon power to the state.

From our experience over the past 18 months since we announced the project we can relate to every stakeholder here today that planning, permitting and building an IGCC with CCS project is extremely difficult to accomplish. And we need help to make it work.

We need regulations that make clear the requirements for CCS development and deployment. We need the energy market to evolve into one that accounts for the externalities of air pollution and climate change.

We need to see leadership, courage and innovation from our regulators and elected officials to embrace this technology now for real climate mitigation.

For those of us who are taking the financial risk to bring this essential climate change mitigation strategy to market we need your help to make it viable. A role for low carbon power via CCS needs to be established. CCS will never be commercial unless we economically value the act of not putting CO2 into the atmosphere.

And government should also recognize and value the co-benefits that CCS offers, including climate protection, energy security, energy diversity, new jobs, U.S,. intellectual property, improved air quality, new technology development and demonstration. For all of these benefits the California Energy Commission is the very agency that can and should embrace CCS.

The oil and gas industry has over 30 years of experience transporting and injecting CO2 into deep geological formations for enhanced oil recovery. Around 30 million tons per year of CO2 are being injected today. Combining EOR with CCS is genuinely a win/win for California and the U.S. It prevents CO2 from entering the atmosphere and it provides us with additional energy security through increased domestic oil production.

The CEC, through this report, should embrace, encourage, facilitate and, in fact, incentivize enhanced oil recovery for purposes of low carbon power project and general climate mitigation measures.

And importantly, the report should be very careful not to deter oil and gas operators from participating in early projects.

Moving on to the area of public acceptance and education. After working in the CCS policy and commercial arena for the past two years, it has become apparent that there's a genuine need for an effective education and awareness program in California that proves to lawmakers, regulators and the general public that CCS is a safe and important element of the strategy to stabilize carbon emissions.

CCS has been extensively studied by industry, government and academia, yet there is little understanding of the technology outside of those who are already familiar with it. The lack of knowledge about CCS invites those who would oppose the technology to exploit this uncertainty, to sow confusion and fear in order to serve their parochial policy agenda.

Those who see CCS as a key tool to slow and reduce the flow of carbon into the atmosphere must assertively educate key decisionmakers, stakeholders and the general public about the function, safety and importance of CCS. And we can start now.

In the short term every measure that society deploys to save the planet from the consequences of climate change will cost something extra. CCS is no different. But in the long term the benefits of a climate stabilization strategy that includes CCS are incalculable.

And the quicker that we can deploy these technologies, the sooner we will be able to reduce the costs of their use. To that end I would like to submit for the record recent testimony we provided to the U.S. House of Representatives Select Committee on energy independence and global warming, which, among other things, recommends an early move or deployment program that promotes the startup of power plants with CCS by 2015 through 2020.

In conclusion, Hydrogen Energy believes that CCS is available today to play a significant role in reducing greenhouse gas emissions and addressing climate change. However, we need the government's help in encouraging the timely development and deployment of CCS on a commercial scale.

Thank you.

ASSOCIATE MEMBER GEESMAN: Have you filed your permit application yet?

MS. RAU: No. We have not yet filed to the CEC. We had actually publicly announced that we were shooting for December of this year. We're still working through some issues of CO_2 offtake and storage. And so it'll be delayed. It's going slower --

ASSOCIATE MEMBER GEESMAN: Delayed from December?

MS. RAU: It's going slower than we had originally intended. And that's one of the reasons why I'm here today, and make the case that this is difficult.

ASSOCIATE MEMBER GEESMAN: Do you have a new target filing date?

MS. RAU: I don't. No.

ASSOCIATE MEMBER GEESMAN: Okay.

MS. RAU: But we are actually in communication with your siting staff and keeping them apprised.

PRESIDING MEMBER PFANNENSTIEL: Thanks. George Peridas from Natural Resources Defense Council.

MR. PERIDAS: Thank you. My name is George Peridas from the Natural Resources Defense Council. And a big thank you to the Commission for hosting today's workshop. And also a big thank you to the AB-1925 report, who put together what I believe to be a really excellent document. And I think it really bears repeating that the people dealing with these issues were really top notch and respected throughout the world for the work. So very many thanks to you for your hard work.

I'd like to offer some brief comments today, and we'll be offering also written comments by Thursday's deadline. One thing that I don't think the report captured that well was to summarize what the states of knowledge that we have today around this technology is.

It does happen throughout the document in many places, and my mind quite clearly, but we have to bear in mind that the audience for this report and the message will not necessarily have the technical expertise that is present in this room. I think there is space to frame maybe the introduction, or the beginning of the report, to summarize more clearly what we know about CCS; on what grounds do we believe that it can be safe; what evidence do we have to date that it has performed up to expectations.

As in NRDC we take this issue very seriously and CCS is a topic that we've been following for a number of years now, over a decade. And we feel very -- we feel that we do have a very strong responsibility to do sufficient due diligence before we come out supporting a technology like that, which at first sight and first contact, does appear somewhat unconventional.

Nonetheless, we have done this work, and we are convinced right now that it can be done safely and can contribute to reducing the greenhouse gas emissions.

I'm not saying it's the cheapest or the most desirable way of mitigating carbon emissions. There are better things to do. Increasing energy efficiency obviously is the number one priority, and renewable energy should follow straight on.

Nonetheless, the urgency of emission reductions is dictated by the climate problem today, also means that we do have to take this approach very seriously, as well. China is building the equivalent of two coal plants every week. These leave us with a great carbon footprint for a great number of decades. Five to six decades is a typical lifetime for a coal plant.

Our calculations show that coal, by itself, as a fossil fuel, will bust the carbon budgets that we need to stay within in the 21st century in order to avoid dangerous climate change. So I do not think that we have the option not to use this technology, as well.

California is considered justifiably as a state within the nation that is leading the debates, action and policies on reducing carbon emissions. And yet we have a paradox when it comes to carbon capture and storage that we do not yet have the awareness or the emphasis placed on the role that this technology should play in the future.

And I think that it is entirely apt for California to be leading on that front, as well.

it doesn't mean that the state, itself, will have to deploy this technology to the extent that other states or other nations will, unless I think it would be a great missed opportunity and entirely the wrong message to send out if California were not to come to terms with this technology and also specify the parameters and the policies that will be needed for it to contribute to reducing carbon emissions.

On the policy front we mentioned that the immediate-term or short-term carbon prices under a cap-and-trade scheme might not be sufficient to secure the deployment of this technology. I would entirely agree with that.

And at the federal level, you will see that certain proposals, legislative proposals, in the 110th Congress have sought to address this problem specifically. One is the proposal by Senator Bingaman who has put together a separate set of allowances with a multiplier which decreases over time, to incentivize technologies like CCS that will need additional stability and lack of volatility, and the price at the beginning, and also a higher value of allowance.

We believe, in NRDC, that a mixture of a new source performance standard, such as the SB-1368, 1100 pounds per megawatt hour standards in combination with a policy that will spread the costs from first movers to the entire sector, the electricity sector, whichever sector we choose, is appropriate.

And there's a big difference between saying that CCS is prohibitively expensive. It might be for a specific development by a specific plant. Nonetheless, we believe that the cost of spreading that over an entire sector is perfectly manageable and will have very minimal effects on our economy.

And let's bear in mind that we will not suddenly be replacing the entire industrial power generation fleet with one that deploys CCS. It will be done a handful of plants at a time.

ASSOCIATE MEMBER GEESMAN: In fact, this past spring when the MIT study on coal was published, as I recall your organization came out with a report that included the recommendation that CCS be included as a requirement for all new pulverized coal plants built from this point onward, isn't that right?

MR. PERIDAS: That is correct. I was a

joint author to the report. And the position of the organization is that we will be opposed to any new coal developments unless they capture and permanently sequester the vast majority of their emissions. And we believe that this --

ASSOCIATE MEMBER GEESMAN: And wouldn't that have a higher likelihood of actually accelerating this technology or perhaps making it happen at all, rather than waiting for Senator Bingaman's $12 with a cap approach to creating cheese for mice?

MR. PERIDAS: I don't want to get strong. We do believe that there are other proposals in Congress right now that would get to what we consider to be more acceptable carbon reductions. And a safety valve set at $12 is far from ideal. And it clearly falls short of incentivizing CCS in a substantial way, or in a meaningful way. So I think we would see a very limited number of developments at non-power generation applications of CCS under such a proposal without special provisions.

The next point I'd like to touch on is that of liability, which is also dealt with in the report. We do believe that there is an issue that needs to be discussed there, but I would urge the discussion to be slightly more informed.

Instead of talking of long-term liability in a blanket fashion, I think we need to be talking about what liabilities specifically we need to address. And there are a number of things that we can be talking about.

Is it the liability for contaminated groundwater? Is it the liability for a well that needs replugging? I think there are many subsets and more nuanced ways that we can be talking about when it comes to long-term liability. And we will have a much more meaningful discussion if we start adopting that framework, rather than speaking of blanket liability relief, or blanket indemnification. I don't think that's consistent with the message that CCS can be done today, and that it's safe. I do believe that this is the case, but we need to slowly reframe the liability discussion.

On the regulatory fronts I will agree with the report and its conclusions that it is one of the areas where we need to do additional work. And that it is one of the depressing areas. We do believe that the technology is far more developed.

I think that Liz, in her report, in her presentation today, summarized it very well. It is about piecing together existing technology; it is not about coming up with something completely new.

And one of the major areas that needs work right now is that of regulations. What I did see in the report was an analysis of how current regulatory frameworks fall short in some cases of providing industry with what they need to pursue these projects.

What we would like to see, from my point of view, is also an analysis of the ability for current regulations to safeguard public health and environments to the degree required. And unless I'm misunderstanding what was written in the report, and that's, I guess, a question for Sarah, the conclusion that I drew was that current regulations do have the potential to do that, the scope for that. But there is, nonetheless, no guarantee that this will be the case. Because it will be, in some cases, at the discretion of whoever is implementing the regulations.

And so if I'm drawing the right conclusions, what I'm trying to get at is there is a clear need to put together the parameters that will insure that this happens every time, and to insure the public and ourselves that these projects will be done under adequate safeguards for health and environments.

And finally, and this is by no means a criticism or a bad comment, I'm listed as a reviewer of the report. I did not get a chance to do that. And so I would like to make sure that's put straight for the record.

And many thanks again for what made an excellent read. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, George. We'll look forward to your written comments.

Anybody else in the audience? Anybody on WebEx?

MS. BURTON: Yes.

MS. KELLER: This is James and he has a question. James? James?

MR. MOSHER: Hello, this is James Mosher.

MS. KELLER: Yes, you can go ahead and ask your question.

MR. MOSHER: Yeah, my question was just

regarding the $20 per ton offset that was stated in the report with regard to EOR projects. I was just wondering how that was generated, or what the source was for that figure.

MR. MYHRE: The source was Howard Herzog and his colleagues at the Massachusetts Institute of Technology. And I don't have further information on that. There's not an ongoing large market for CO2 EOR in California like there is in Texas. So it would be hard to get California-specific information. But obviously there are some sort of assumptions behind that figure.

I believe, and it's also worth mentioning, this is not Howard's observation, but my own, that large scale application of CO2 capture on industrial sources would ten to make a significant quantity of CO2 available for enhanced oil recovery operators.

And simple supply-and-demand economics might suggest that over time the price of CO2 would go down. And so developers of CCS projects are undoubtedly factoring that into their economics.

MR. MOSHER: Thank yo.

PRESIDING MEMBER PFANNENSTIEL: Thank

you. Anything further?

I want to thank the staff and the report development team for a really useful, meaty and interesting report. I think it did give the IEPR Committee a lot of material.

And thank you all, the panel, for helping educate us. Thank you, Liz, I think your discussion today was very helpful for all of us.

And with nothing further -- anything further from the dais? We'll be adjourned.

(Whereupon, at 3:03 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 18th day of October, 2007.