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09-IEP-1P

DATE May 18 2009

RECD. JUN 05 2009

JOINT COMMITTEE WORKSHOP
BEFORE THE
CALIFORNIA ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

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

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

MONDAY, MAY 18, 2009

9:02 A.M.

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

CALIFORNIA REPORTING, LLC
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Electricity and Natural Gas Committee

ADVISORS and STAFF PRESENT

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Kelly Birkinshaw, Advisor to Commissioner James Boyd

Larry Myer

Martha Krebs

ALSO PRESENT

Elizabeth Burton
Lawrence Livermore National Laboratory (LLNL)

Craig Hart
Alston & Bird

Dale Simbeck
SFA Pacific

Geir Bollsaeter
Alston & Bird

Mary Jane Coombs
California Air Resources Board (CARB or ARB)

Michael Stettner
California Department of Conservation

David Albright
United States EPA

Susann Nordrum
Chevron Energy Technology

Tiffany Rau
Hydrogen Energy

Mark Nelson

Southern California Edison (SCE)

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George Peridas
Natural Resources Defense Council (NRDC)

PUBLIC COMMENTS/QUESTIONS

Susan Patterson
Gas Technology Institute

Richard Myhre
Bevilacqua Kight, Inc. (BKI)

Will Johnson
Visage Energy

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CEC

I n d e x

	Page
Proceedings	1
Opening Remarks	1
Commissioner Byron	1
Background/Overview	2
Martha Krebs	2
Carbon Capture and Sequestration	7
Martha Krebs	7
Report AB 1925 - Carbon Capture and Storage	17
Elizabeth Burton	17
CCS Financial, Legal and Regulatory Barriers	38
Craig Hart	38
<u>Panel Discussion</u>	<u>52</u>
<u>Moderators:</u>	
<u>Michael Stettner, CA Department of Conservation, David</u>	
<u>Albright, U.S. EPA, Susann Nordrum, Chevron Energy Technology</u>	
<u>Tiffany Rau, Hydrogen Energy, Mark Nelson, Southern</u>	
<u>California Edison (SCE), George Peridas, Natural Resources</u>	
<u>Defense Council (NRDC)</u>	
<u>Public Comment/Questions</u>	
<u>Susan Patterson, Gas Technology Institute, Richard Myhre,</u>	
<u>Bevilacqua Kight, Inc. (BKI), Will Johnson, Visage Energy,</u>	
<u>Pierre du Vair, CEC</u>	

INDEX CONTINUED

<u>Advances in CO2 technologies</u>	107
<u>Dale Simbeck presentation</u>	107
<u>California's low-carbon fuel standard</u>	
<u>and opportunities for CCS</u>	132
<u>Geir Vollsaeter</u>	132
<u>AB 32 updates and opportunities</u>	148
<u>Mary Jane Coombs</u>	148

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1 | P R O C E E D I N G S

2 | 9:02 a.m.

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

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

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

24 | So next I'd like to thank all of the presenters,

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

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

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

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

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

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

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

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

24 This is just to remind you that California has

1 aggressive goals for greenhouse gas reduction. And in large
2 measure, here in the -- the work of ND 32 is focused on the
3 2020 market. And -- but the long-term issue of the 2050
4 targets are where the carbon sequestration -- the option of
5 carbon capture and sequestration come into play. What we do,
6 both in California and in the nation over the next decade
7 will demonstrate whether or not in the period beyond 2020,
8 carbon capture and sequestration is a capable, reliable
9 mitigation measure for reducing CO2 emissions.

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

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

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

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1 discussions later today.

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

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

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

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

24 The DOE Regional Partnerships Program, this is

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

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

17 WESTCARB, the West Coast Regional Carbon
18 Sequestration Partnership, has grown to more than 80
19 organizations and the California Energy Commission
20 Recruiter, their program is the manager of that, of this
21 partnership. It has helped to inform policy and AB 1925 was
22 passed, I think, in 2007 and required a report which was
23 prepared in 2008 and then a follow-up report will be heard in
24 2010. Actually, I think it was 2007. We included it as part

1 of the IEPR process.

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

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

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

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

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

22 So in -- I want -- the next two slides are kind of
23 summaries of the challenges for CCS. And although there are
24 real technical challenges for carbon capture and

1 sequestration, in many ways it represents the new application
2 for the existing technologies but with a different scale in
3 terms of physical scale and the sense of time frame in which
4 implementation may have to occur.

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

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

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

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21 The other significant element is infrastructure and
22 how you link carbon dioxide sources in a grid, pipelines that
23 we're trucking, whatever, you know, building that kind of
24 infrastructure. Again, it's well-known, but it is -- it

1 | needs to be thought through and evaluated with respect to
2 | both costs and environment health and safety. But these are
3 | things we have done before.

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

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

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

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1 regions, regional offices, how is that to be managed.

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

10 So I think that's my introduction.

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

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

15 MS. KREBS: Yes, sir.

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

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

20 PRESIDING MEMBER BYRON: You had mentioned
21 something off presentation about Secretary Chu announcing
22 last Friday that a one and a half billion dollar available
23 for covering capture/sequestration for industrial sources. I
24 did not hear that. Do you -- do we know anything more about

1 how those funds will be distributed?

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

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

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

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

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

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

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

1 dollars in.

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

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

6 MS. PATTERSON: Okay, thanks.

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

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

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

24 And then that will take us up to noon. Lunch is on

1 your own. In the afternoon, we're going to then have a few
2 more presentations, first on sort of an update on the
3 advances on catracide (phonetic). Then, even though we'll be
4 talking about it in the panel discussion, a little bit more
5 in depth overview on California's fuel standards and its
6 implications for CCS and then talk on AB 32, an update on AB
7 32.

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

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

20 There are some copies of the report available out on
21 the table, you can pick them up. You can also download it
22 from the Energy Commission website, so it is publicly
23 available. And if you have comments on it, I would certainly
24 appreciate hearing from you. We are scheduled to do a second

1 report that is due out in November of 2010 and I'll tell you
2 what the reasons behind that are in just a few minutes.

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

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

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

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

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

15 And given those two questions, they're really, sort
16 of two conclusions for the first one or two considerations.
17 California imports a great deal of its electricity and most
18 of that is from coal fired plants out of state. It's 20 to
19 30 percent of our electricity and about half of the inventory
20 greenhouse gas emissions from the power sector. Any CCS
21 strategy really has to take this into consideration to be
22 effective or optimized.

23 Within State, the largest point sources are natural
24 gas power plants and then plants and refineries. And there

1 are certainly different ways of dealing with those than you
2 might use if you're just looking at power sector emissions.

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

14 We basically decided to write that second report in
15 consultation with the Legislative staff because so much is
16 happening in CCS and will be happening. The conclusions of
17 the pilot studies, a lot of the early commercial work will be
18 coming out in the next couple years. So we thought having
19 the final say to the Legislature at the end of '07 really
20 wasn't doing the best job for them. So we offered, silly us,
21 to write a second report due in 2010. And of course you know
22 the old line in the Legislation is always we'll use existing
23 assets, no new funding. So anyway, we've committed ourself
24 to a second report and that is why it's really important if

1 you have comments on the first report to make sure Larry or I
2 are aware of those.

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

10 Putting those screening on that 104, they eliminated
11 77 of the basins. Twenty-seven of them met those screening
12 criteria and that still left us with 38,000 square miles of
13 turf that are potentially good sequestration sites. This
14 includes the largest ten basins in the State and includes the
15 Sacramento, San Joaquin, Ventura, L.A., Eel River basins. So
16 these are substantial sequestration resources.

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

1 It's important to note within these basins that oil
2 and gas fields are very common. These in and of themselves
3 are potentially good sequestration sites. They have
4 extensive capacity, about 5,000 million metric tons of CO2.
5 And the other important factor, I think, is this oil and gas
6 has been trapped in structures, that have trapped -- these
7 are buoyant fluids, so they tend to want to migrate upward
8 just like CO2 does. But these basins have the capacity to
9 trap these things over geologic time scales for millions of
10 years, in other words. So, they've been demonstrated through
11 geologic time to be good traps.

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

22 However, having said that, and keeping in mind how
23 much electricity we import as well as transportation fuel
24 that we export, I think it's important for California to

1 approach CCS in a regional context.

2 Electricity imports, again, into California.

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

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

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

21 SB 1368, which put in a mission standard on long-
22 term base of power purchases, is another consideration
23 because this certainly affects imported coal generated power.
24 Again, imported power is 60 out of the 107 million metric

1 tons in the 2004 Greenhouse Gas Inventory. Addition of CCS
2 would allow these coal generating power stations that send
3 their electricity to us to meet that standard which is
4 defined as 1100 pounds of CO2 per megawatt hour.

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

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

16 Other early economic opportunities that were
17 identified in the report include ethanol and bio-refineries
18 as Martha mentioned previously. We don't have very many
19 plants right now, so they're not going to make a big dent in
20 our current emissions inventory, but if we went that
21 direction for transportation fuels there, we can certainly
22 expect a lot more of them to be built. Twenty-five hundred
23 metric tons of CO2 are produced for every million gallons of
24 ethanol and these emissions are pretty much pure, so you

1 don't have to go through the economic pain of putting a
2 separation and capture plan onto your facility. And
3 separation as you will -- you either know or will hear about
4 is by far the largest cost associated with CCS.

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

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

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

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

1 of operators in the San Joaquin Valley.

2 Eighty percent of our emissions sources are within
3 50 kilometers of a potential site. EOR operations do recycle
4 CO2 because they buy it and they want to optimize its use.
5 But even with that, they get 30 to 60 percent of the injected
6 volumes left underground. So they do sequester even when
7 they're in operation and obviously that could change with
8 time if they were to become true sequestration sites instead
9 of EOR facilities.

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

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

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

24 So the components of technical readiness that we

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

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

11 First, pipelines, CO2 pipelines are very mature
12 technologies. I mentioned they're all over the U.S., over
13 3,000 miles of CO2 pipeline delivering over ten trillion
14 cubic feet of gas. A regulatory framework exists in
15 California. We do have some pipelines here in state. The
16 Office of the State Fire Marshall oversees those regulations.
17 An experienced work force exists.

18 And importantly, the CO2 EOR Industry which pipes
19 all this CO2 reports no serious injuries or deaths associated
20 with CO2 pipelines. So it's a very mature safety technology.
21 There are automatic waft valve closures, spacings regulated
22 by the U.S. Department of Transportation. A lot of these
23 pipelines have telemetry for 24-hour real-time monitoring so
24 if there is a leak, if they're compromised for some reason,

1 which is apparently quite rare, even so, they immediately
2 isolate that piece of the pipe that's breached with the block
3 valves and they go out and they fix it and they know about it
4 pretty much right away.

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

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

16 The comments they made were addition of CCS to new
17 or even existing power plants has potential effects on
18 regulatory frameworks such as CEQA and Warren/Alquist for
19 siting the new plants or even retrofitting existing
20 facilities. Since the Energy Commission is the CEQA lead
21 agency for -- or will likely be the lead agency for CCS
22 associated with power plants, this aspect needs to be
23 included in any follow up studies done in preparation for the
24 2010 report. And those will be happening fairly soon, we

1 hope. So those discussions will be. So again, any input
2 will be appreciated.

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

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

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

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

8 Risk perception and awareness is certainly going to
9 affect rates of adoption. Surveys here in the U.S. and in
10 Europe have repeatedly shown that the public is concerned
11 most about harm or damage from leakage of CO2. They're also
12 concerned by accountability and stewardship issues over these
13 extremely long time scales.

14 Other risks that have been identified probably more
15 by scientists than the public, are damage from induce seismic
16 or brine migration or pressure pulses and saline formations
17 and climate change risk from cumulative slow leakage of CO2
18 back into the atmosphere. In other words, the thing is going
19 to just keep leaking slowly over time. So in 200 years,
20 you've lost a significant amount of what you put into the
21 ground, what was the point of doing it. So we have to find
22 some way of verifying that the stuff has stayed in storage.

23 It's important, I think, to note in particular
24 because scientists have a really bad habit of talking about

1 pools or bubbles of CO2 underground. And some of the public
2 surveys I read, people really believed this, okay. These are
3 not actually pools or bubbles. The reservoir rocks are
4 sandstones and the typical sort of reservoir sandstone is
5 shown there by that red, very solid blob of outcropping
6 sandstone. They have high permeability, but it's all in
7 very, very course spaces between the grains. So it's not
8 like we have a cave underground that this big pool of CO2 is
9 sitting in it, that if it's breached, it's all going to
10 suddenly burp out and be a major hazard. This stuff has to -
11 - it, in case of a leak, has to wind its way out from between
12 all of those little sand grains where the stuff is actually
13 sequestered as shown on the lower right there.

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

23 The sequestration reservoir has to have very
24 specific attributes. Injectivity means how easy is it to get

1 the CO2 into the rock and displace those subsurface fluids.
2 Capacity is how much CO2 the rock will hold and this includes
3 dissolve phases or mineral phase, phases created by the
4 action. And integrity which is the ability of the sealing
5 locks to keep that CO2 in the reservoir and also to make sure
6 that there aren't any leaking orphan wells or falls on the
7 site.

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

12 Monitoring must track CO2 migration, detect leaks
13 and verify storage. There are a number of mature techniques
14 that are available. This is from the CO2 capture project and
15 it just illustrates all the different technologies that can
16 be used to track CO2 and to monitor for leakage.

17 Remediation and mitigation addresses what to do in
18 case of a leak and, again, these aren't technologies that we
19 have to invent. They already exist. They're used by the
20 Natural Gas Storage industry and by the oil industry. And
21 again, this just lists, for example, I don't know how well
22 you can read that, but for (e), if CO2 escapes by a poorly
23 plugged or abandoned wells, you can go out and replug that
24 well and put in some CO2 resistant cement.

1 It's important also to realize and remember that CO2
2 is not really a toxic substance unless it's present in hugely
3 high concentrations. And if it reaches the surface, whether
4 or not it's a hazard depends on the concentrations and on
5 atmospheric conditions. For example, in Mammoth Mountain,
6 you see signs all over the place, CO2 hazard area. This is
7 magmatic emissions that build up into soils and they do cause
8 tree kills. And they can also and have killed humans and
9 animals when the CO2 gets trapped in low places like snow
10 caves and you have stagnant atmospheric conditions you can
11 get buildup to lethal percentages.

12 In the tree-kill areas, the soil's CO2 is on the
13 order of 80 to 90 percent. However, in Italy, people live
14 around fumerolles that give off 150 tons a day of CO2 with no
15 negative effects at all. Crystal Geyser, you see a family
16 playing around this CO2 geyser which was created by an
17 abandoned exploration well that penetrated a natural CO2
18 reservoir and it geysers that CO2 and water and no one has
19 ever been harmed by that.

20 Two just very quick summary slides. You'll be
21 hearing a lot more about this. Regulatory means the
22 technology and knowledge exists to inform the regulations. A
23 demonstration and early projects are needed to provide test
24 cases. And given the differences, I think it's very

1 important that we have a regulatory framework that's
2 flexible, that can be streamlined and that is predictable and
3 consistent across the different types of reservoirs and
4 sources that it's going to need to be -- to regulate.

5 Statutory needs, given the long-term nature, again,
6 this just sort of reiterates things Martha already brought
7 up. Long-term stewardship is a big one. How do we protect
8 people and the environment in the long term and assure that
9 we've had climate change mitigation over the long term.

10 There are ambiguities in pore space ownership. Liability
11 limits have to be defined and how they follow ownership. And
12 we have to address issues that arise from any kind of a CARP
13 and credit or cap-and-trade system that is put in place.

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

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

1 the 2010 report.

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

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

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

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

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

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

15 PRESIDING MEMBER BYRON: Good, thank you.

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

1 MS. BURTON: I am not sure how much I can get into
2 this in 30 seconds, but I'll give it a go. With the Mammoth
3 Mountain situation, the CO2 is vented from volcanic emissions
4 from a magma source that's fairly deep and it causes a lot of
5 seismic activity and I think everybody's kind of familiar
6 with the whole kind of environmental tenuous situation that
7 really from a geological standpoint exists at Mammoth.

8 The CO2 leaks out of -- is a volcanic emission. All
9 volcanoes do this to some degree and it builds up in the soil
10 in the case of the tree kills. Again, they're only very
11 isolated places in Mammoth where that does happen. It's not
12 pervasive over the whole extent of the magma chamber. And
13 when it reaches a certain critical threshold, then the trees
14 die. We are doing some studies of how we can do aerial
15 surveys to pick up plant stress early in the case of a
16 leakage.

17 In terms of the physics and chemistry of a potential
18 CO2 leak, it doesn't look at all like the sort of process
19 that is happening at Mammoth. So there are fundamental
20 scientific differences in the way those leaks happen and what
21 we would predict with a CO2 reservoir. So in the case of a
22 magma, you've got something that's come up and there's not
23 necessarily any kind of a cap rock to prevent those emissions
24 from coming up. The placement of the magma creates a lot of

1 faults and fissures that are natural leakage pathways into
2 the overlying soil.

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

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

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

23 This was developed by Baker & McKinsey. They're
24 estimating there are a dozen different studies with different

1 numbers. So this is really only a -- to give you the
2 magnitude. That by 2015, they expect the cost to be
3 somewhere in the 60 to 90 Euro-ton range for a demonstration
4 phase project. And what they're hoping to get is to cut that
5 in half or better over time. But as we stand now, for
6 demonstration projects, whether they're commercial scale or
7 not, that the cost is quite high, in the up to 90 Euro-ton.

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

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

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

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

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

21 I'm not going to go through all of these points in
22 what is meant to be an overview talk, but we will get into a
23 few of them. Before going into the individual issues, what I
24 want to point out to you is we do have some empirical data on

1 liability issues from the Phase 2 Regional Sequestration
2 Partner, the DOE effort.

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

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

19 These were how some of those liability issues were
20 dealt with. In six of the 19 projects, liability was assumed
21 by a project party. In five of the projects, five of the 19,
22 liability was not raised in the negotiations but it ended up
23 being essentially not allocated or accepted by a party. At
24 the time that the study was done, two were under negotiation,

1 one project was canceled in part as a result of liability
2 issues, three declined to comment, two too early to know at
3 the time of the study.

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

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

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

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

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15 However, I will note that it leaves the potential
16 for RCRA and CERCLA liability depending upon whether that CO2
17 that is being injected has other elements in it. Okay, CO2
18 alone, not a contaminate per se, but if there is something in
19 it that is hazardous, that could cause RCRA and CERCLA
20 liability and the panel will get into those issues a bit
21 more.

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

1 context.

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

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

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

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

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22 Also this Bill includes very significant credits and
23 financial incentives. And again, going to that financial
24 piece, I think you can still see in Waxman/Markey that there

1 is a significant amount of effort being paid to the
2 economics. And the federal government is going to be better
3 suited to dealing with the economics than they are the
4 liability issues which will remain a state area.

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5 Senator Bingaman has issued a draft Liability Bill.

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6 It's due for markup later this week. That will pick up
7 liability for ten projects, up to ten projects. The projects
8 must be one million tons or greater per year in a geologic
9 formation. Any industrial source will qualify. They are

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10 intended to be fully integrated system. So in other words,
11 not the kind of test injections we saw in Phase 2, but more
12 the full scale, commercial projects that we're seeing
13 industry propose and also in the deal with Phase 3.

14 They subject for the projects that apply and DOE
15 would then accept them. They have to demonstrate that they
16 have met strict operating and post-closure requirements.

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17 There'll be a financial insurance mechanism. They will, in
18 fact, pay for this coverage through an indemnity fee that's
19 been -- which we don't know what the details will be, but if
20 this Bill is to be passed, presumably there's going to be a

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21 rule-making regulation that would operationalize this
22 language, that it's the net present value of the expected
23 payouts under the Bill for liability. And the liability
24 that's being covered is property and tort indemnity starting

1 ten years after the safe closure and of the injection and the
2 plume has reached equilibrium.

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3 So what you're seeing is a proposed Liability Bill
4 for ten projects. This could very well go and support Phase

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5 3 of the DOE projects and it could be for other things, too,
6 it's open. But again, it's almost an experiment because ten

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7 projects, you know, we already have upwards of seven projects
8 in the DOE Phase 3 and if we want to see this technology
9 really incentivize, and start moving down the buy-down curve,
10 we need to see more aggressive approaches to look to
11 liability.

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12 State actions. We are seeing activity in the 30
13 plus states. The story is most interesting at the state
14 level. And the legislation that we're seeing is -- ranges in
15 a number areas, but these are the main ones: siting,
16 operation closure requirements, pore and CO2 ownership,
17 financial insurances, financial incentives in some cases

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18 where states are getting in and looking at the economics,
19 state assumption of liability and usually after it's --
20 again, after a ten-year period, jurisdiction among regulators
21 within the state, who has responsibility, and a number of
22 states of doing work study groups.

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23 And here's what several of the leaders -- and these
24 are the -- I'm going to show you two slides of states that

1 have an active legislation. I'm not going to show you
2 pending legislation. There's 20 plus more states that have
3 legislation pending.

4 | Wyoming has been one of the most aggressive. They
5 have gone ahead and defined pore and CO2 ownership. They
6 have specified that the owner has liability for injected --
7 that the injector of CO2 has liability for that CO2. They
8 have developed the unitization law, similar to what's used in
9 the oil and gas area, for unitizing and aggregating
10 subsurface formations for CO2 injection. They've also
11 clarified that the mineral estate is dominant over the pore
12 estate. So Wyoming has done quite a bit of thinking. Their
13 philosophy has been we don't want to move the sticks around
14 among players, but we definitely want to see this technology
15 move forward.

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

21 North Dakota has done a lot as well. Again, they've
22 taken on -- they've defined pore ownership, they have a
23 liability transfer mechanism to the state, they have a
24 unitization law, they have a regulatory framework and they

1 have subsidies and a fee-based storage facility fund which is
2 a financial insurance mechanism.

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

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

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

17 MR. MYER: I believe --

18 MR. BIRKINSHAW: I have just one --

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

22 MR. BIRKINSHAW: Yeah, I have just one question.
23 You mentioned that the Feds generally reluctant to interview
24 in a state property law, but that the Bingaman Bill seems to

1 set up a number of mechanisms for these ten projects. Do you
2 envision that there'll have to be changes to state law to --
3 in the places where those projects are located?

4 MR. HART: No, I think they're going to be careful
5 not to tread on the toes of the states. I think that it's
6 extremely significant that they have proceeded like this.

7 And I think they've done it carefully. I mean, they've

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8 limited it to ten. They've retained authority of the DOE to

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9 select those ten. They've subjected them to -- those ten

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10 will have to comply with a number of very strict

11 requirements. And I think all the federal government is

12 doing is saying, we'll indemnify anyone who's quorumed for

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13 property and tort, loss of life and so on, if those issues

14 were to arise, under very -- but within a very strict set of

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15 guidelines.

16 And I think for the federal government to go and
17 take that kind of responsibility for that potential liability
18 doesn't -- that's more of a contractual matter. There are
19 other examples of where the federal government does, indeed,

20 indemnify parties and usually in the defense area and so on,

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21 here, they have contractual relationships. So they can do

22 this. And arguably this is research or demonstration,

23 commercial demonstration, in the public interest. And

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24 they've gone ahead and decided to propose this legislation.

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

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

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

20 They also had the economic infrastructure in place
21 in order to go ahead and support research by national labs
22 and universities on their fields. And without getting into
23 too many details, you know, the EOR operators provided a
24 great -- they were great partners in these projects. They

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1 provided needed support across a range of activities, whether
2 it was unitizing land or dealing with property rights owners
3 whose consents were needed and so on. They were actually
4 quite significant in moving the ball forward in Phase 2.

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

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

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

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

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

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

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

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

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

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

24 UNKNOWN SPEAKER: Mike, it's up.

1 MR. STETTNER: I might just follow it.

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

3 advancement.

4 MR. STETTNER: That's okay, I don't need it. I'm

5 going to just jump to the last slide of my PowerPoint, and

6 that's to emphasize that the Division of Oil and Gas and

7 Geothermal Resource has been regulating oil and gas wells

8 since 1915 and water flood began in the 1940s and gas soon

9 after. This one's labeled, right?

10 So we have about 60 years of experience or more, 60

11 plus years of experience in regulating underground injection,

12 whether it's fluids or gas. I just wanted to make --

13 emphasize that point.

14 Our current authority is regulated to the fluids

15 that are associated, imminently associated with oil and gas

16 production. And that includes EOR and water disposal. And

17 it can go in -- it does include zones that are not oil and

18 gas bearing zones. But the fluid has to be imminently

19 associated with oil and gas.

20 And as an analogy, if you permeant a -- if a

21 cogeneration facility is permeant and the steam from that

22 facility is used in an EOR operation, the fluid that is

23 associated with that power plant, that co-gen, can then be

24 injected into a water disposal well under our purview.

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Deleted: UNKNOWN SPEAKER: Yeah.
MR. STETTNER:

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

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

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

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

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1 MR. HART: David.

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

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

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

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23 Certainly, there's a lot going on at EPA and in
24 Congress pertaining to carbon capture and storage, but this

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1 particular rule is just about injection and the protection of
2 underground sources of drinking water.

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

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7 So one of the -- the first of the four issues I
8 wanted to talk about briefly is post-injection site care and
9 closure. And in the proposed rule, we proposed a fifth year
10 time period for post-injection site care. And what that
11 means is after the cessation of injection at a site, there

12 would be a 50-year time period when that site would need to
13 be monitored to track the travel of the CO2 plume and the
14 pressure response and subsurface to see that that -- that the
15 CO2 is immobilized and that the pressure had dissipated and
16 built up in the formation.

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

1 some people may wish to discuss.

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

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

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

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

1 liability in the long term.

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

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

13 The question is how do you establish when the well
14 is no longer a Class 2 well and becomes a Class 6 well that
15 is -- specifically doesn't (indiscernible) for
16 geosequestration. You create a bright line and some people
17 felt like there's really no difference and we should just
18 allow there to be a seamless transition from Class 2 to Class
19 6.

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

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1 government Class 2 wells.

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

14 I think this is an interesting topic of discussion
15 because the Class 6 wells would be part of 1422 Primacy.
16 That's the other section of the Safe Drinking Water Act,
17 dealing with primacy. And right now, the State of California
18 does not have 1422 Primacy. They have primacy only for Class
19 2 wells, as I noted.

20 So it is a key issue. Obviously, EPA knows that
21 many states are going to want to take delegation of Class 6
22 injection wells and there are a few other states that have
23 this situation where there's Class 2 only primacy right now
24 and the Agency is looking at how that would be handled. We

1 certainly got plenty of comments suggesting that we should
2 allow Class 6 primacy for states to take Class 6 primacy as a
3 stand-alone without respect to any other classes of injection
4 wells.

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

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

23 Just had a few points we wanted to make on CO2
24 capture and sequestration. I think the word "liability" has

1 come up once and twice and certainly as a business in
2 California, that's something we need to understand how that's
3 going to work. It needs to be addressed. You know, we feel
4 that there are cost effective financial mechanisms like
5 letters of credit, bonds or third-party insurance. Or there
6 could be a public/private funded entity. I think Craig
7 mentioned some of the other states are working towards that.
8 So I think that's, you know, really a prominent issue that we
9 need to take care of in order to have certainty going
10 forward.

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

22 The third point is and I think that this has also
23 been made, is that the petroleum industry really has had a
24 lot of experience and expertise in the subsurface. And, you

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*4:12:34) your comments

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1 know, sequestration of carbon dioxide under the ground has a
2 lot of ventral analogs and certainly with the enhanced oil
3 recovery operations, that the idea of injecting CO2 into the
4 deep subsurface is not some brand new step-up thing, but
5 really an extension of activities that we already undertake.

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

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

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

23 The Hydrogen Energy California Project which is kind
24 of referred to as HECA for short is considered an early mover

1 commercial project.

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

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

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

22 The reason why the liability needs to be resolved
23 and addressed in the long term is simply because private
24 entities don't last in perpetuity. So there -- it has to be

1 addressed ultimately. But we don't feel that it's a barrier
2 to entry and in some cases I feel like maybe it's an excuse
3 not to deploy CCS. So kind of we're -- as I said, we're an
4 early mover. We're proceeding. We feel that in the interest
5 of climate policy, Congress or perhaps the states will
6 address with the issue post-closure liability in a reasonable
7 manner. And that's worth proceeding.

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

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

21 And I also wanted to point out because I know there
22 are some risks associated or perceived risks associated with
23 CO2 transport and pipeline. The HECA Project itself, all the
24 linears for that project are within five miles of the site,

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1 including the CO2 pipeline. So that isn't an issue that's
2 causing us from going -- keeping us from going forward
3 either.

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

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

22 We believe that HECA Plant will make a real
23 contribution to 2020 AB 32 goals. Saying that, however, I do
24 want to make it clear that if we're -- the HECA Project, even

1 though it will make, we think it will make a difference in
2 meeting 2020 goals and demonstrating the viability of CCS for
3 post-2020 Bills, we don't necessarily expect for the HECA
4 Project to play into AB 32's cap-and-trade type of the
5 scheme. Instead it was the value of the product being in the
6 low carbon base load attribute of what the plant would be
7 producing as well as the technology demonstration. This is
8 all being worked through at the PUC.

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

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

1 where I'll stop.

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

6 For the utilities, especially in California, CCS is
7 a fairly logical continuation of work we've done. In the
8 80s, Edison built the first integrated gas location combine
9 cycle of Coolwater. So carbon capture and storage really is
10 a follow-on to that.

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

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

23 And with Hydrogen Energy, we are, as Tiffany said,
24 trying to evaluate both the technological feasibility and the

1 commercial reasonableness of that project and what future
2 participation the utilities could have in that.

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

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

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

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

1 33 percent and there's a lot more intermittency in the
2 system, there will be a higher premium on not being base-
3 loaded because you'll need -- you know, we as a state will
4 need the ability to ramp more -- specially you throw in ones
5 through pooling and, you know, potentially the removal of
6 those plants. So we'll wind up with a state that has less
7 ability to ramp and integrate intermittents.

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

15 Tiffany hit one thing directly on the head which is
16 full scale plants aren't going to move forward without cost
17 recovery certainty. And to the extent that all first-of-the-
18 kind plants tend to be above-market costs, we need to
19 understand very clearly how to recover those above-market
20 costs. And whether that's through, you know, government
21 subsidies that essentially bring the plants down to market
22 production costs or whether it's through a broad sharing of
23 above-market costs, you know, almost preferably with all
24 Californians, but you know, sort of at a minimum with all

1 benefiting customers, I think that's going to be a
2 requirement. So cost recovery is sort of a terrestrial issue
3 for getting plants built.

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

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

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

24 And then I had one other observation from Craig's

1 discussion and that regards the, you know, the fact that at a
2 state level, the property rights where the CO2 is injected
3 are going to vary from California to Arizona to Nevada. And,
4 you know, we've seen this in renewables. It's been, I would
5 argue, probably an impediment to the (indiscernible) market
6 during the credit market and that is that you've got
7 different rules in different states about what qualifies for
8 what and how things work.

9 And to the extent that, you know, and previously
10 someone had said, you know, you go where the carbon is if you
11 want to remove it. To the extent that California desires to
12 decarbonize coal in other states, we're going to need very,
13 very clear understandings of what the ground rules are for
14 that CO2 that's been removed that's been put in the ground
15 because, you know, we risk having open-ended liability, we
16 risk having, you know, essentially a claw-back problem if
17 it's determined that the mass balance didn't work and, you
18 know, perhaps instead of 80 percent capture, you only had 60
19 percent capture.

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

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

5 MR. HART: George.

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

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

18 Our brief analysis shows that in the next 25 years,
19 what with projected investments and qualifying plants alone
20 will, over the lifetime, emit more CO₂ than humanity has
21 admitted since the beginning of the industrial age from all
22 used coal. This is a huge legacy which we cannot afford to
23 put into the atmosphere. People talk about 415 EM CO₂'s
24 levels, these are coming down every year as scientists

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1 revisits data. And if we do let this happen, we will be on
2 (indiscernible) when it comes to these emissions. And we are
3 already late doing so.

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

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

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

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

1 2020 type of release, I -- we do not believe that CCS is
2 needed. Nonetheless, I have to challenge, like Tiffany did,
3 the notion that CCS cannot contribute to 2020 time lines
4 (indiscernible) 2007 either draft would send it's --
5 mentioned the inability of CCS to contribute to 2020 goals.
6 We do not think this is true. We think the technology is
7 ready to contribute to these goals. Nonetheless, we still
8 think that the state can meet those goals without CCS.

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

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

24 Now, I have not yet seen a similar leadership role

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1 or commitment on the CCS front on behalf of the state. And
2 this is despite California having a number of very
3 accomplished centers of excellence. And this includes
4 Stanford, it includes Lawrence Labs, Berkeley and Livermore
5 in no particular order.

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

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

23 The Bill was caught in a very basic level of debate
24 around CCS which (indiscernible) for example, often. This is

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1 one of the indicators of the lack of knowledge around the
2 technology. Lake Nyos was another example of volcanic
3 emission in Africa which led to fatalities and animal kills
4 and plant kills and so on. It has nothing to do with
5 sequestration site. The two are fundamentally different and
6 on opposing ends of the spectrum. Nonetheless, this is what
7 was the focal point of the debate around the Bill and I think
8 it was an indication of how much is known within the
9 Legislature about the technology.

10 Unfortunately I think the whole Bill was also caught
11 up very much (indiscernible), a very controversial and in my
12 view, badly located time proposal and (indiscernible).

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13 Nonetheless, I haven't yet seen any evidence that the debate
14 or the level of the debate on CCS has changed. According to
15 the State, in think this is a task that we all have ahead of
16 us if we are to take this technology to where it's needed to
17 contribute to emission refuse.

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

23 Now, the task is very much to catch up with what EPA
24 is doing and what a number of other states are doing on the

1 legal and regulatory front. And we've seen some encouraging
2 movements on the CPC front, at least lately. I do not know
3 any of the details, I'm not expressing supporting it, but at
4 least we can see that the debate is happening in an
5 intelligent and productive way.

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

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

18 Finally, two things. We need to be sensitive to
19 siting issues. Having a technology that's worthwhile is not
20 the same as saying that it can be sited anywhere. We need to
21 be sensitive to the locale, we need to be sensitive to local
22 communities and also to environmental justice issues. And we
23 have a situation, California has -- someone stated that
24 someone being a major industrial facilities are located in

1 disadvantaged areas. These are pollution hot spots and the
2 local communities have been calling now for a number of years
3 to put out (indiscernible) facilities. And I do not think
4 that it's credible to say that there are none. In fact, if
5 you drive by a refinery, I think you can unquestionably smell
6 it.

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

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14 There were a number of examples that include hazard
15 recovery, waste disposal, acid gas injection in Canada,
16 natural gas storage where the practice is developed and
17 flourished without a surrounding indemnity regime. I do not
18 see how this is fundamentally different. CCS, I think, is a
19 very definite problem that we need to get through, but it's
20 something that we need to be very, very careful how we
21 portray this. I don't think that taking a sledgehammer to a
22 problem that tweezers can solve is advisable. And I think
23 that we run a risk of painting CCS in a very bad light and I
24 think that liability in a blanket indemnity regime is not

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1 commensurate with the inherent risks of CCS which, in most
2 cases, will drop off after injection.

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

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12 So with that, I will thank you.

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

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

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19 MR. HART: Please.

20 PRESIDING MEMBER BYRON: And it goes back to in your
21 initial presentation and I think this panel might be able to
22 contribute in a significant way. There's a number of states,
23 obviously, that moved forward on other legislation. What can
24 we learn from that legislation? I don't think we've gotten

1 much here in California at this point and clearly we're going
2 to have to do this on somewhat of a regional basis, if not
3 federal. So what can we learn from some of that legislation
4 to those of you who that have evaluated or looked at what
5 other states have done?

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

8 PRESIDING MEMBER BRYON: Please.

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

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

23 And just for purposes of clarification, the
24 liability that we're talking about is not operational

1 liability. People that work in the industry who inject CO2,
2 you know are or are asked to do it in an R&D context before a
3 commercial operation of it, we don't know what -- based on
4 the survey work, we don't think there's any issue there. So
5 we really are talking about the long-term liability, the
6 stewardship liabilities which were referred to.

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

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

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

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

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

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

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

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

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

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

21 MR. HART: The -- a note. The cost of acquiring the
22 rights to a subsurface area that's capable of sequestering
23 substantial amounts of CO2, we have a little bit of
24 experience with this from the Phase 2 projects because one of

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1 them was, again, in the EOR context. The partnership that
2 was evolved could not have accomplished that without any EOR
3 partner and I understand it took two years of lawyer time. I
4 don't know exactly what the deal was, but it was significant.

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

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

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

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

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

8 MR. HART: David.

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

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

21 The final rule that comes out in the next year or 18
22 months approximately, I think it's important for states to
23 think about, as I think George mentioned, how the state, if
24 they want to take delegation of plastics, wells, oversight of

1 geosequestration, how that would work in the state.
2 Basically, a state would have to demonstrate -- a state would
3 either have to adopt the EPA's rules for the mechanics of how
4 CO2 is sequestered or write their own rules, but EPA would
5 then need to determine if those rules were at least as
6 stringent as the federal rules.

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

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

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

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

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

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

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

19 And I -- also one of the points that I think that
20 George made is that, summarizing, that a blank check should
21 not be offered here and I happen to be in agreement with
22 that. I don't think it's necessary. If you look at --
23 there's a number of ways to limit or restrict the kinds of
24 liability protections that are offered. If the state does

1 take liability on this, a number of states have, they do it
2 after a period, usually ten years.

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

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

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

23 So whether it is the federal government or the
24 states or the private sector or a project party, the only two

1 that we've seen move, I think, on long-term liability is the
2 EOR community and the Phase 1 and those are very small scale
3 projects, which Mike Stettner pointed out. At larger scale,
4 they may not work, they may not work the same way. And the
5 other is states. And there's several examples of states that
6 have taken on liability.

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

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

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

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

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

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

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

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

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

20 MR. STETTNER: I think one thing we need to keep in
21 mind when we're talking about EOR versus saline is that we
22 have a lot of data on oil and gas fields. You know, the
23 fluid has been in there, gases have been in those zones for
24 millions of years. What we don't have is a lot of data on

My understanding there is

1 saline reservoirs. So that may be an issue or that will be
2 an issue.

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

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

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

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

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

1 with the intermediate term through financial vehicles, but
2 long-term, you know, very problematic.

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

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

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

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

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

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

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

23 MR. HART: Anybody else have any comments?

24 MR. STETTNER: I just wanted to define the points,

1 what George has referred to as our bonding requirements.

2 Technically our bonding requirements are for the drilling of
3 the well and that's not for the long-term operation, although
4 the operators do maintain a blanket bond, they just carry
5 through with their operations. Technically that bond could
6 be released if after six months of consecutive production or
7 injection.

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

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

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

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

23 MR. PERIDAS: I think the siting of any industrial
24 facility also carries environmental gases implications if

1 it's located in certain communities. And there's things
2 (indiscernible) as being supportive of ecology that the
3 technology is a good idea and a needed one and climate
4 portfolio is different than saying with this site of
5 operation can or should be located ever and I was urging an
6 inclusive and rigorous treatment of local community issues
7 when it comes to deciding not just CCS project but any
8 project.

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

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

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

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

9 MR. HART: Thank you. Other questions?

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

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

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1 source (indiscernible) water.

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

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

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

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

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

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

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7 The first few plans, again, cost more than the next
8 10 or 20 and we need to get over that hump. There are
9 provisions that would use a fraction of the revenue from cap-
10 and-trade to give out incentives on the job at the time,
11 sequestered basis for a number of gigawatts. Overseas has
12 deployments on the power tech side and 15 percent of that is
13 set aside for the industrial side.

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

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

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(indiscernible *5:10:21) is the
question that I'm -- I think

24 MR. HART: Mark.

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

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

24 PRESIDING MEMBER BYRON: So if I may, does that have

1 to do with the cost of carbon? Or are you looking for
2 loaning guarantees or tax credits or something else, other
3 vehicles like that?

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

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

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

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1 the number one role, I think, that the State can play.

2 MR. HART: Thank you, Tiffany.

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

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

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

4 MR. HART: Thank you. Susann.

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

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

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

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

3 MR. HART: Thank you. David.

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

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

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

22 Our authority right now is specific to oil and gas,
23 expiration and production operations. For us to start
24 implementing or to implement or ponticate [sic] regulations

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1 for gas storage, CO2 storage, we need to have that statutory
2 authority first. That's where we would like to go. And we
3 are willing to accept that responsibility. And we would be
4 looking at, you know, a primacy application very much similar
5 to what we did for the Class 2. That's what we envision.

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

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

24 And then finally, I think if the State really wants

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

13 Other comments? Other questions?

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

23 I think this is only one example of what needs to be
24 done, but I think all these policies that were mentioned and

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1 measures that were mentioned by the panel, if they stand a
2 good chance of being active, will require, I think,
3 sufficient knowledge of the (indiscernible) of CCS by the
4 Legislature, and which I don't yet see that it's there. And
5 not just the Legislature, but also the variety of
6 stakeholders involved in it and such and such.

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7 MR. HART: Thank you.

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

14 MR. HART: No, please.

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

22 Those early movers, these are going to be
23 complicated projects. They're going to take on new issues
24 that we really haven't dealt with before in the State and

1 when you're also bringing in new agencies either at the state
2 and/or federal level, it's going to complicate the issue even
3 more. But I'm very sensitive to that and also to the
4 importance of carbon capture and sequestration. We've got
5 some great expertise as demonstrated on this panel this
6 morning and I'd like to really thank all those that were here
7 today, particularly those who gave up some of their Sunday to
8 be here as well.

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

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

18 MR. HART: Thank you, Commissioner. And I guess
19 without further questions from the audience, I'd like to,
20 once again, thank the Committee. This was a very good
21 discussion of the issues facing us on the policy side for the
22 CCS. And I think what we now do is we have a break for lunch
23 and we will reconvene here at 1:00 if I have that -- 1:15,
24 1:15. And lunch is on your own. So thank you very much.

1 (Lunch recess)

2 MR. MYER: I guess we'll pick up where we left off.

3 And so, this afternoon, we have some more focus discussion
4 about several issues, specifically related to the -- to both,
5 to the legal and regulatory aspects, but beginning with a bit
6 of a update on the capture side of the issues, technological
7 issues.

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

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

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

18 MR. MYER: Half hour, half hour.

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

21 MR. MEYER: That's not a problem.

22 MR. SIMBECK: Okay. What I'm going to do, you --
23 everyone here has the slides and hopefully the ones on the
24 WebEx can gain access to those slides as well. They're -- I

1 can't get this to go. Okay. What I'm going to do is they're
2 very busy slides. They're really talking points of a lot of
3 detail I won't have time to discuss. But if I do a good job
4 in the presentation, you'll be encouraged to go back and look
5 at some more of the detail.

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

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

22 In general terms, we only have four ways to reduce
23 man-made CO2 emissions. The first two you don't talk about
24 much and that's reducing world population, reducing standard

1 of living. But the fact is, this is a recession year
2 worldwide. So this year, CO2 worldwide will go down with the
3 recession.

4 What you have to focus on is reducing energy
5 intensity and carbon intensity and the particular
6 applications that apply to the big elephants in the room
7 which are the United States and China. The United States is
8 20 percent of worldwide CO2, but people tend to lose sight
9 they're also 20 percent of the worldwide gross domestic
10 product.

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

14 Here is the overall CO2 emissions for the U.S.,
15 broken out by application fuel. And I did this to point out
16 an important point and that is that there is -- the two big
17 dogs that control CO2 emissions in this country is oil for
18 transportation and coal for power generation. And that's
19 about the same for the world. So each of those are about 40
20 percent on a world basis as well as an overall U.S. basis. So
21 you really have to focus on those two, the coal for power
22 generation and the liquid fuels for transportation.

23 Now, California is very uniquely different. And
24 that is transportation is by far the biggest CO2 emitter

1 here. Even when you include the imported coal-based
2 electricity, electricity is still relatively small here due
3 to our electric use being small and also the large amount of
4 natural gas use makes that CO2 from electricity relatively
5 small here. So we're unique compared to the rest of the
6 United States and the rest of the world.

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

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

22 A key part of our private client work on this issue
23 is the power generators will be forced to meet a
24 disproportionate share of the reduction. You can't really

1 put a lot of this on to the residentials with their
2 transportation. There isn't an effective way to do that on
3 cars unless you change the biomass fuels which tend to be a
4 little expensive. Other is you can't put it on industrials
5 because they have to compete in international business. And
6 so you can literally force the industrials to move to China.
7 And the net effect is, you just increase emissions whereas
8 the power plants can't move to China and they're the big
9 users of coal as well. So they're the ideal ones to look at
10 in terms of these reductions, but will have those fair shares
11 across all of the sectors that consume electricity will help
12 pay for that.

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

20 But even without that coal use, I think we still
21 need CO2 capture and storage to meet these ambitious goals.
22 We're going to want to look at this to develop in long term,
23 perhaps to use the biomass, as I have mentioned before, to
24 get that infrastructure in place. And I think the key

1 challenge we have is public acceptance of this as an option.

2 But I think we need it if we plan to meet these ambitious
3 goals.

4 A very quick overview on capture and storage,
5 there's three key parts. You need a location where you can
6 store large amounts of CO2 in geologic formations and we have
7 those in California; large point sources for economies of
8 scale, we have some of those; and then you have to get to a
9 high concentration, compress it to supercritical conditions
10 to store it as well. So those are the three main parts.

11 And as Elizabeth mentioned this morning, the U.S.
12 has been a world leader in CO2 capture and storage, but we
13 don't think of it that way. It's -- normally, CO2 for
14 enhanced oil recovery and we have these pipeline systems on
15 the slide. And I think more importantly in this slide are
16 those squares. Those squares are anthropogenic, man-made
17 CO2's that are captured and used as opposed to natural CO2's.
18 So roughly, of this 40 million tons a year of CO2 that we
19 store, about 20 percent of that comes from man-made CO2 and
20 we're getting these benefits of this enhanced oil recovery as
21 well.

22 Now, I'm going to walk through the four -- the three
23 different capture systems. And from this last slide,
24 hopefully you can see that we have these two large systems

1 and actually both are pre-combustion. And so, pre-combustion
2 is being done commercially in a very large scale, but not in
3 power plants. That's the issue that's missing.

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

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

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

24 The attributes of a pre-combustion, I think the

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

7 Post-combustion is slightly less developed at this
8 point. It tends to be harder to do in flue gas because of
9 the presence of oxygen, very low pressure, very low CO2,
10 what's referred to as partial pressure, taking the total
11 system pressure times the percentage of CO2. It's very low.
12 And so that operation tends to require a lot of circulation,
13 a lot of stripping steam. And that's where you get the large
14 power and capacity losses.

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

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

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

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

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

21 Attributes of oxy combustion is that you can -- you
22 avoid these complexities of pre-combustion which is more a
23 very complex chemical process. You can potentially avoid the
24 stack, have 100 percent recovery which would be a nice thing

1 for permitting, not to have stack or any emissions at all.
2 Potentially you can retrofit these as well, and nice
3 retrofits are when they increase capacity. And there's two
4 places where oxy combustion can retrofit to increase
5 capacity; fluid cap crackers and loyal industry which I don't
6 have time to explain the details of those, and also cement
7 kilns.

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

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

24 In post-combustion, a major -- a breakthrough was

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

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

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

1 The first is where the costs lie and generally
2 speaking, about 15 percent of those costs are to get to the
3 pure CO2 stream, about 25 percent of the costs to compress up
4 to the supercritical conditions and about 25 percent of the
5 costs with a pipeline injection, geologic storage and
6 monitoring. So it's important to think about it in those
7 percentages because if you do CO2 for enhanced oil recovery,
8 that last 25 percent, instead of being a cost, can be a
9 slight positive revenue stream, so you can literally go from
10 a negative 25 to a plus 25 and potentially eliminate maybe
11 half of the costs in enhanced oil recovery. So that's an
12 important early mover.

13 Another issue with CO2 capture and storage is most
14 of those costs are associated with additional capital and
15 internal energy use. In gross terms, for a new plant with
16 fossil fuels, considering without capture and then with
17 capture, you're looking at capacity and efficiency drop to
18 somewhere between 15 and 30 percent.

19 Now, you can potentially avoid those big efficiency
20 drops if you go into retrofits where you basically rebuild
21 the retrofit to a state-of-the-art, more efficient plant.
22 And even with the capture, you end up with about the same
23 efficiency as the old plant, but now a zero admissions. But
24 those retrofits are much more expensive than just the -- or

1 the rebuilds are much more expensive than just the retrofit.

2 So you have to watch in your costs, but you can avoid the

3 efficiency capacity loss by doing that.

4 Also, the best thing to do when you look at CO2

5 capture and storage is think about the increase in product

6 costs. And I'm going to use electricity here. I don't

7 really like to use a CO2 avoidance cost because they depend

8 on the baseline. And that's very tricky. But you do have to

9 think about the CO2 avoidance cost because what that really

10 means is that's the minimum carbon tax that would be required

11 to economically consider capture and storage. So that's why

12 people calculate that, because of its importance.

13 And the last line on this slide is the formula.

14 It's a very simple formula. It's the difference in the cost

15 of the product, in this case electricity, with the capture

16 and without. And then it's the amount of CO2 per unit of

17 energy to the atmosphere, originally versus what you have to

18 capture.

19 And I point that out because of this next slide and

20 that is there's three components to the CO2 avoidance cost.

21 It's the capital charges, the amount of CO2 you've recovered

22 and the fuel price in the efficiency, especially efficiency

23 loss. And so, what that says, and Elizabeth said the same

24 thing this morning, and that was coal or, in California,

1 coke, the capital charge will be very high, but the amount of
2 CO2 you avoid and the fuel cost are both -- well, the amount
3 of CO2 you avoid is very large and the fuel cost is low.
4 Whereas with natural gas, the capital cost won't be as big on
5 that investment for capture, but the amount of CO2 you avoid
6 is half as much and the energy price is much more. And, so
7 you tend to get in the situation that if natural gas prices
8 are high, the CO2 capture cost with natural gas tend to be
9 higher than with coal or coke. And that's an important
10 economic issue to be concerned with.

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

17 A caveat in that is trying to estimate costs right
18 now is dangerous to your health because costs went so high
19 the last three years and now, they're starting to drop. And
20 also here in California they tend to be higher costs than the
21 rest of the country. Compared to the U.S. Gulf Coast, about
22 25 percent higher construction costs here.

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

1 California costs will be higher than that. And so the first
2 thing on costs I like to ask myself is what's the minimum CO2
3 tax I would need for a power plant operator to consider CO2
4 capture and storage. And that would be what's -- when the
5 price of electricity is the same, for him to have capture or
6 him to just vent the CO2 and pay the tax. And so, for this
7 generic, a new coal plant about \$15 per metric ton of CO2 and
8 that's about 11 cent electricity. I've increased my
9 electric cost from about 7 cent electricity to 11 cents and
10 that's for a base-load plant that runs all the time. That
11 would be industrial power rates, U.S. Gulf Coast, a few years
12 old dollars. For California, our industrial rates are 10
13 cents now. So for California, you'd be looking at probably
14 going to perhaps 14 to 15 cent electricity for a base-load
15 industrial rates. Roughly about a 25 to 30 percent increase
16 in electric price.

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

22 The other thing you have to ask is at that \$50 per
23 metric ton CO2 tax where I got the new coal plants to
24 consider capture, what natural gas price could they pay and

1 avoid capture? And because your first choice would be to
2 avoid that big investment in capture plus all that financial
3 risk and liability and just look at natural gas. Well, I can
4 afford to pay as high as the 11 to 12 dollar per million BTU
5 natural gas with that carbon tax to get the same price of
6 electricity. And that's much less investment and much less
7 risk.

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

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

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

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

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

21 The oxy fuel is a smaller scale. They're hoping to
22 build a demo with that. Even as that proceeds right now,
23 they still have the successful pilot plant where they do have
24 a source of CO2. The beauty of the clean energy systems with

1 the oxy fuel is that you can build this without stack at all
2 and makes permitting much easier for these zero emission
3 plants.

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

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

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

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

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

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

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

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

1 going as quickly as possible.

2 California, I think, has even a higher cost
3 associated with the CO2 capture and storage mainly due to our
4 lack of coal use and our dominant natural gas use for power
5 generation and our high natural gas costs, those will tend to
6 be high.

7 We do have the advantages, though, of the geologic
8 formations. They're very attractive for storage along with
9 the enhanced oil recoveries, both EOR, CO2, but also the
10 steam stimulation EOR of heavy oils for co-gen. So I think
11 those two can neutralize these higher costs in California to
12 give us an advantage to move on CO2 capture and storage.

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

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

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

23 When we look at the incremental costs of a kilowatt
24 hour dispatched into the grids, what analysis have you done,

1 or have you done any analysis, say, by adding four gigawatts
2 of natural gas combined cycle post-combustion, distributed
3 that over the total consumption and what that would look
4 like?

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

9 MR. VOLLSAETER: That would be all in.

10 MR. SIMBECK: All in.

11 MR. VOLLSAETER: All in.

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

14 MR. VOLLSAETER: Reasonable costs and everything
15 else.

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

17 MR. VOLLSAETER: Yes.

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

22 I would caution you that in a carbon-constrained
23 world, all our analysis shows that natural gas is a big
24 winner. And so, as you bring in more carbon tax and try to

1 get reductions in CO2, that natural gas price will be going
2 up. And so that's going to impact this marginal low dispatch
3 of these natural gas plants and would tend to favor these
4 petroleum coke plants at the very low, marginal low dispatch.

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

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

13 MR. SIMBECK: Yes.

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

16 MR. SIMBECK: No, no. Most of them just vent the
17 CO2. They get the pure CO2 stream and just vent it. It's
18 not being done to take out the CO2. It's being done to
19 produce the pure hydrogen stream which the plant's build to
20 do.

21 And so it's very hard to go around the world and
22 find the gas location plant that doesn't remove most of the
23 carbon. But most of the plants, after they remove it, just
24 vent it. There's a few plants that are recovering that CO2

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

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

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

18 So the -- there's two things that are going to bring
19 down costs, learning by doing on the commercial ones, but
20 also improved technologies and then commercializing those.
21 How much will come from each is always of great debate. And
22 if you talk to any researcher, it's always advance
23 technology, the technology of the future forever. And the
24 problem is forever. And you talk to the commercial people

1 that we need demo plants and the truth is somewhere in
2 between. You do need both; learning by doing and constantly
3 improving and working on advance technologies. But be honest
4 to yourself how long it takes a pilot technology to get to
5 commercial acceptance. There's quite a learning curve there
6 to gain market share.

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

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

22 So there's always new technologies coming that look
23 exciting. As you get into it, though, you have to be honest
24 to yourself which ones don't make it. And actually, you

1 learn more from being wrong than being right if you're honest
2 about why certain technologies didn't make it. And you learn
3 from that through the others.

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

12 MR. MYHRE: Thanks, Dale.

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

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

23 As you might see from the name, I'm not native, but
24 I've spent a decade in this state and here in Sacramento and

1 it's a pleasure to be back. The other thing that's maybe
2 worthwhile mentioning is that I worked with the CO2
3 capturers, CO2 management for about a decade. I'm also in
4 renewables and biomass. And had the fortune to be able to
5 work on carbon capture and storage projects from natural gas,
6 coal and other things.

7
8 And what's happening with regards to regulation and
9 the drive towards lower carbon intensity, both in what we
10 consume in terms of fuel, power, steel, aluminum and the
11 likes is terribly exciting and it also enables us to get a
12 much, much better view on the life cycle of the things that
13 we consume. And in that regard, California has gone, by far,
14 the longest in terms of setting an EPS Board or Mission
15 Performance Standard for power. And also developed a Low
16 Carbon Fuel Standard.

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

21 As has been said here, my experience is that we
22 capture and release CO2 today. So I know the technology
23 works, but we're not getting in the ground. And there are
24 show stoppers out there that makes it hard. And some of

1 those have been highlighted today with regulatory issues,
2 lack of testing and often times, long lead times in order to
3 get these projects to fruition.

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

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

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

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

1 WESTCARB is part of, is absolutely critical.

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

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

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

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

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1 sector.

2 The various point sources that you have from the
3 production of hydrocarbons and to where it ends up in the car
4 is very amenable to CO2 management in several places.

5 There's two particular places and that's in the upstream
6 where you produce.

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

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

16 This is a slide that I've borrowed from Total.
17 That's the French oil company. They have a carbon capture
18 and storage project operating today in Southern France. I
19 believe that is a oxy fired project, very small scale, but in
20 Southern France, but they've had success in storage. They've
21 developed this slide and it tells you, I'm going to tell the
22 story about it. And if you look to the left, conventional
23 oil, it's easy to produce, it's easy to refine, it's not very
24 CO2 intensive. The lowest CO2 intensity barrel you can

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1 produce today is probably around five, six, seven kilos of
2 CO2 associated per barrel by the time you get it into the
3 market.

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

10 The Low Carbon Fuel Standard have gone through most
11 of the technical background work and there's volumes of it.
12 And it's interesting to read. And if you go down the value
13 chain of where you get your energy from, you will see that
14 although pipeline gas can be a clean and used product. For
15 us Europeans, by the time you've hauled gas out of Siberia,
16 across Russia, through the Ukraine and into Europe, by the
17 time you have some methane leaks, a lot of compression, you
18 will see the carbon intensity increase as it comes in.

19 You'll see liquid natural gas here. That's a global
20 commodity that travels around the world. It's conversion can
21 have 25 to 30 percent losses in conversion. And by the time
22 you bring it in, that needs to be factored in and that's what
23 the Low Carbon Fuel Center does in principal. But in terms
24 of using natural gas or compressed natural gas for fuel, that

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1 comes in.

2 Far off to the right, is what's being considered for
3 coal and Dale mentioned this, as you do the Syngas process
4 off of coal, you can convert it to diesel or a range of
5 different products. This technology has been around for a
6 very long time and the CO2 can easily be taken out and it's
7 the storage part of it that's challenging.

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

12 The opportunities that exist within Low Carbon Fuel
13 Standard and AB 32, is the CO2 reductions can be had through
14 CCS. So far, I've figured out that AB 32 allows for those
15 reductions to be counted in.

16 I'm left a little uncertain whether if you take the
17 CO2 as a -- through carbon capture and storage from a
18 refinery, whether that's eventually counted as a reduction in
19 the fuel you're supplying out. And if that is the case, we
20 have a challenge where reductions that could be had here in
21 refineries might not be given credits of the final fuel that
22 you deliver out into the market. If that is not resolved, we
23 could likely undertake projects here, but where maybe credit
24 is needed, credit is not given. So maybe a little regulatory

1 tuneup to that process is needed.

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

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

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

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

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

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

1 counts for 10 percent. But due to the slate of crudes that
2 California refines, the CO2, the hydrogen requirement for
3 refining here is much higher. Hence, the CO2 emissions
4 associated with hydrogen production here will be higher in
5 order to provide the standard of quality of the fuels that
6 California needs and requires.

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

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

16 But you can understand from this slide, just by
17 going after the CO2 that comes off that Syngas process when
18 you steam or form hydrogen can lead to a significant
19 reduction of CO2 from a particular refinery, just from the
20 hydrogen alone. By the time you address the cracker, you're
21 talking substantial reductions. And by the time you do this
22 even 10 percent on the Low Carbon Fuel Standard from the well
23 to the tank, your emissions will drop significantly because
24 refining in California is a significant input per unit energy

1 that's delivered out into the market.

2 By this nice graphic from Conoco Phillips, this
3 catalytic cracker that they've shown for an example is a
4 50,000 barrel a day cracker. With 90 percent capture, you
5 can take out 1,000 tons a day of CO2; 360,000 tons a year
6 with operational time from one cracker at 50,000 barrel a
7 day. Refineries in the U.S. range from, you know, the
8 smaller ones, 20-30,000 a barrel a day, probably up to 250-
9 300,000 barrels a day to the largest ones. And if you add it
10 up, this is a very large, single source point.

11 The challenge with addressing a cracker is that the
12 gas quality that comes off there is not easy to deal with.
13 This is a major technological challenge that can be solved
14 because engineers knows how to do this. It can be solved,
15 but it's an expensive source to go at and it's going to
16 require innovation and deployment in order to get comfortable
17 with the quality of gases that are mixed together with the
18 CO2 when you try to strip out the CO2 for storage.

19 Hydrogen production. Ninety percent of California's
20 hydrogen comes from natural gas and by-products from the
21 refinery. In this process, you can see on the bottom that in
22 order to produce the hydrogen to the quality you need, you
23 need to strip the CO2 out. And this CO2 today is not in very
24 high concentration, but it's stripped and vented. So this

1 could be an opportunity at numerous refineries where
2 additional concentration of the CO2 that comes off of the CO2
3 removal process here is used and put into a pipeline system
4 and injected into suitable storage.

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

17 So, together with carbon capture off of hydrogen
18 reformers and with the bio-fuel inputs, you get an even lower
19 carbon footprint for the hydrogen, compared to electrolysis
20 of hydrogen which is commonplace in many other places around
21 the world. But if you fuel that with the carbon intensity of
22 electricity, the net gain or the net loss is quite
23 significant because the conversion factor for the
24 electrolysis is really low compared to steam reforming as you

1 see here. And if you use unmitigated coal, conventional coal
2 power, your carbon intensity is going to be significantly
3 higher.

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

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

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

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

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1 sources and inject it into the offshore.

2 This flow chart tells you where the emissions are.

3 Back in 2002, the refinery was in the fourth quartile,
4 meaning an under-performing refinery in terms of its energy
5 efficiency. The refinery then decided to install a combined
6 heat co-gen unit on the refinery in order to close down a lot
7 of small boilers. That brought the refinery up to almost
8 first quartile which means a very good energy efficiency
9 index globally.

10 But given that normally has a particular focus on
11 CO2 capture and storage, the government has required CO2
12 capture off of this facility. So these are the plans that
13 have been developed and that is to strip out 870,000 tons a
14 year of CO2 from the cracker at the refinery. And another
15 1.3, almost 1.4 million tons from the combined heat and power
16 unit which is natural gas powered.

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

24 But Norway's in the fortunate position of producing

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

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

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

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

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

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

10 When it comes to storage, Norway has undertaken CO2
11 storage and oil -- not in oil sands, but in sandstone which
12 California has plenty of, since 1996. They've injected about
13 a million tons from an oil and gas field -- or a gas field
14 called Sleitner. This storage -- the formation is, I think,
15 250 miles long, is between 30 and 50 miles wide and is 150
16 feet thick. It can store most of Europe's emission for 100
17 years, all in. That's only estimating one to two percent of
18 the total pore space available in that one formation. So
19 it's not -- we're not talking over pressurizing this
20 reservoir with that estimate.

21 So, we remain confident that there's ample storage.
22 And from what I've seen from WESTCARB's investigations, this
23 can be the same, but in order to verify this, pilots, like
24 they've done in Norway, or this is a commercial operation

1 here, needs to be undertaken here, too. It's a scale where
2 confidence is built up.

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

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

14 If you mapped this little plume of CO2 in this
15 formation that the CO2 is in, you won't even see it with a
16 pinpoint. It's that small. But these are not large volumes.
17 It's about a million tons per year that's been injected since
18 1996. Mega-scale coal plants, five-six tons per year,
19 radically more.

20 Another project that I'd like to mention is that CCS
21 offer refineries or capturing CO2 from refineries has been in
22 operation elsewhere. And that's in the Netherlands and Shell
23 has a refinery there called Pernis where CO2 is taking off
24 these processes inside a refinery and it's piped, and the

1 green line you see here is the existing CO2 pipeline that a
2 third party built to supply CO2 to greenhouses. The benefit
3 of that is that they will not need to use CO2 or natural gas
4 for the growing process. So they displace natural gas in the
5 summertime to the equivalent of 170,000 tons of CO2 savings
6 per year. That's quite substantial.

7 There are significant developments in this area.
8 You can see it's densely populated. But this project has
9 now, I think with the Rotterdam Port Authority and a number
10 of other stakeholders, there are plans to significantly
11 expand the amount of CO2 that's put into a pipeline
12 infrastructure network. And as you see down at the bottom,
13 there's a field called bottom index, and there are plans now
14 to, which is the depleted gas fields, there are plans to
15 inject CO2 into these fields for pilot purposes.

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

20 To date, there aren't any protocols that are
21 commonly accepted or approved that makes that process go
22 smoothly. So at present, a company here in the U.S called
23 Bluesource and the North American Carbon Capture and Storage
24 Association has initiated some work to develop protocols to

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1 where you can measure CO2 from when you have it in the
2 upstream and bring it down to final storage. That is
3 important in order to verify the credits that should come
4 from this.

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

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

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

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

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

1 Governor Schwarzenegger in September of 2006. This followed,
2 by about 15 months, an Executive Order that had been signed
3 by the Governor, not quite requiring, but encouraging
4 California to reduce it's greenhouse gas emissions to 1990
5 levels by 2020 and going beyond that, to reduce 80 percent
6 below 1990 levels by 2050. AB 32 specifically address the
7 2020 issue and I'll be talking a little bit about the
8 difference between those two goals today.

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

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

23 And as I mentioned before, that the key goal of the
24 scoping plan in AB 32 itself is to reduce greenhouse gas

1 emission levels back to 1990 levels by the year 2020 which,
2 as we know, is coming up pretty darn quickly. But the
3 scoping plan also looks at measures that will not just enable
4 the State to meet these 2020 levels, but that will make it
5 easier for us to meet the 2050 levels.

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

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

24 And specifically, looking at the scoping plan, I

1 have an outline here of how the different measures on a
2 sector-by-sector basis contribute to those reductions over
3 time.

4 So these are business as usual, total emissions for
5 2020. You can see the large contributions that
6 transportation, electricity, industry, natural gas make to
7 the emissions overall. I'm just going to sort of bring you
8 through some of these. On the right, there are -- there's a
9 general outline of which particular measures are contributing
10 to the reductions outlined in the scoping plan.

11 Now, a large part of the scoping plan reductions
12 come from a greenhouse gas cap-and-trade program, 20 percent
13 of those reductions. And those are going to cover the
14 transportation. By 2015, they will cover the sector of
15 transportation, electricity, natural gas and industry. So if
16 you look at those on that bar on the right side, under total
17 emissions, 456, those are the bottom four blocks there.
18 They're going to be reduced down to those three -- or four
19 sectors, excuse me, are going to be reduced down to 365
20 million metric tons of CO2 equivalent.

21 So I spoke a little bit about the fast time line for
22 reaching those 2020 emission levels. We're on an even faster
23 time line to adopt the regulations for all these measures by
24 the end of 2010. So we have a year and a half. ARB uses a

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1 very formal structure that is used for many areas to elicit
2 public input on this regulatory process. In fact, this
3 afternoon, there is a meeting on the use of set-asides within
4 the cap-and-trade program being held over at ARB on -- if
5 you're interested in offsets at all, on Thursday afternoon,
6 there'll be another public meeting on that. And that just
7 happens to be, I work within the cap-and-trade group at ARB
8 and there are, in any week, probably at least half a dozen
9 public meetings on any of these different measures that I'm
10 going to take more about in a moment.

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

16 So these regulations will be taking effect by
17 January 1st, 2012. There are a number of early action
18 measures that will be in effect before then, but January 1st,
19 2012 is the deadline for all of them.

20 AB 32 and ARB Policy in general outline a number of
21 requirements for any of these scoping plan regulations or
22 measures. As I mentioned before, public process is a very
23 part of that. We have to minimize costs of achieving these
24 reductions and maximize benefits, in particular environmental

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1 benefits. We need to protect low income communities. This
2 was, for the market-base, compliance mechanisms are the cap-
3 and-trade program. This was especially called out,
4 minimizing those impacts.

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

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

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

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

1 1493 automobile role of the tailpipe emissions standards
2 which we are waiting with bated breath for a waiver from US
3 EPA for go-ahead to implement that program.

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

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

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

6 A key part of AB 32 was requiring a greenhouse gas
7 inventory and reporting. The inventory actually started here
8 at CEC and we have estimates for emissions that go through
9 2004, starting in 1990 through 2004. And those estimates,
10 those 1990 estimates, were what was used to establish that
11 target level for 2020. And hopefully any day now, the
12 inventory numbers for -- excuse me, 2004 and beyond will be
13 released.

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

19 Very broadly, the requirement is for any source
20 greater than 25,000 metric tons of CO2 or power plants
21 greater than 1 megawatts and 2500 metric tons of CO2 to
22 report. I will caution you that this will be changing,
23 though. The cap-and-trade program which is going to link to
24 a regional program through the Western Climate Initiative,

1 the WCI standards are 10,000, reporting from facilities that
2 have 10,000 metric tons or greater, CO2E. So that will be
3 part of the cap-and-trade regulation process over the next
4 year and a half.

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

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

19 The reductions from electricity, we're hoping that
20 they will be quite large. While there are approximately 23 -
21 - 23 percent of the overall greenhouse gas emissions come
22 from electricity, both in state and out of state, we're
23 actually looking for more reductions to come from the
24 electricity sector. A few of the majors that are in the

1 scoping plan include looking at zero net energy buildings,
2 stringent building codes. Our new portfolio standard is a
3 key part of that, 33 percent renewables by 2020. And a very
4 key part of it is energy efficiency, becoming more efficient.

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

10 And then the industrial sector, which is responsible
11 for approximately 19 percent of greenhouse gas emissions, is
12 looking at a number of rather small reduction measures. I
13 believe it's something like 1.4 million metric tons of CO2
14 equivalent in reductions by 2020.

15 And these, just to go over them generally and
16 briefly, energy -- we are requiring an energy efficiency and
17 co-benefits audit for large industrial sources. So this
18 would include, important to CCS folks, power plants,
19 refineries and cement plants emitting more than .5 million
20 metric tons of CO2 per year.

21 We're looking at reducing methane emissions in oil
22 and gas products, reducing leaks in gas transmission and from
23 incomplete combustion, limiting the emissions from
24 refineries, refinery flares, excuse me, and then removing the

1 current fugitive methane exemption from most refinery VOC
2 regulations.

3 As I mentioned earlier, the cap-and-trade program is
4 a very large part of the program for reducing greenhouse gas
5 emissions. And I want to -- a key point I want to make is
6 that the cap that I'm going to be talking about is a subset
7 of the statewide target for 2020, whereas the target --
8 actually, I have the wrong number up there. The target for
9 2020 is 422 million metric tons of CO2 equivalent for all
10 sectors for all of the economy. The cap for the four sectors
11 I mentioned, major industrial sources, transportation fuels,
12 residential/natural gas fuels and electricity is 365 million
13 metric tons of CO2 equivalent.

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

24 So this is -- this graft just gives you an idea of

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

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

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

24 So the idea with the cap-and-trade program, that the

1 benefit, we see it as providing, compared to a carbon tax, is
2 that, one, there is an absolute limit on the number, on the
3 amount of greenhouse gas emissions which would not happen
4 with -- likely not happen with the carbon tax. And then, it
5 also allows sources to seek out the most cost effective
6 reductions.

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

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

17 All right, finally to which you really want to hear
18 about is what does the scoping plan say about geologic
19 sequestration. The scoping plan, first of all, acknowledges
20 the great research that has been carried out by WESTCARB.
21 And it does recognize the potential for utilizing CCS for
22 emissions from a number of different sources. And encourages
23 the State to support, and I'll just quote here, "California
24 should both support near term advancement of the technology

1 and ensure that an adequate framework is in place to provide
2 credit for CCS projects when appropriate."

3 Now, here's the key that -- you're probably
4 wondering why, you know, why aren't there CCS majors in the
5 scoping plan itself. Well the ARB views CCS primarily as a
6 2050 reduction technology. That's not to say that CCS could
7 not provide reductions by 2020, but as you saw from the
8 schedule earlier, we have a very large burden on our plate,
9 challenge on our plate within the next couple of years. And
10 we're looking primarily at the very low hanging fruit to
11 achieve the reductions for 2020. That said, we certainly
12 what to encourage projects that would enable reduction, those
13 huge 2050 reductions to take place.

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

19 But we're also working very closely with the state's
20 Climate Action team to make sure there's consistency across
21 the many state agencies working on this to especially prevent
22 double-counting of any reductions. And my office and other
23 offices within the ARB are updating our Board twice a year on
24 progress and all our board meetings are available on the web

1 if you ever want to check on those. In fact, we have an
2 update coming up at the June board meeting. I think it's the
3 26th of June.

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

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

22 And that top website, I encourage you to check out
23 often for updates. And there's my contact information as
24 well as Elizabeth's if you're interested in talking with us

1 more. I do want to specify, I work for the Office of Climate
2 Change in the cap-and-trade program, so that is my area of
3 expertise. And Elizabeth is the point person in the agency
4 on geologic sequestration. So thank you for your attention.

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

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

8 MS. COOMBS: Hi, Kelly.

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

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

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

22 MS. COOMBS: Yeah, that was that maximum of 45
23 percent reductions. So that's a small number relative to the
24 number of allowances, what we call the allowances within the

1 cap-and-trade program.

2 MR. MHYRE: Rich Mhyre, BKI. Thanks, Mary Jane.

3 Maybe this is sort of a segway to the discussion portion of
4 the meeting, but I heard what you said, I'm just wondering if
5 you can help me understand it from the point of view of a
6 particular company. Let's say and electric utility.

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

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

24 MS. COOMBS: Okay, you're talking in a sense about

1 the point of regulation for these different things and the
2 point of regulation is different for different measures
3 within the scoping plan.

4 So for instance, with the cap-and-trade program,
5 they're going to be regulated for -- they -- a source, an
6 emitter will be responsible for the emissions for turning
7 over allowances to -- basically, a permit to emit a certain
8 amount of CO2 for that facility. So that's not a company-
9 specific requirement.

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

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

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

1 tell whether -- I couldn't read the fine print.

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

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

15 MS. COOMBS: That goes -- you're correct, CCS was
16 not in that chart. And that goes back to the Board viewing
17 CCS not as much of a 2020 technology, a goal to meet those
18 2020 reductions, but meeting reductions beyond that.

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

20 MS. COOMBS: Actually, let me expand a bit. The
21 measures that were included in the scoping plan are meant to
22 be quite conservative and that was part of the trepidation --
23 I shouldn't use a word that strong, but the -- because there
24 aren't these large-scale projects going on with CCS, the

1 agency, the Board decided, you know, it wasn't something that
2 would be included.

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

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

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

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

19 MR. JOHNSON: Yeah, when you --

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

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

23 MS. COOMBS: Yeah.

24 MR. JOHNSON: -- if that's your rule or goal, you

1 know, should you wait till -- or if you're saying, well,
2 we'll wait till 2020 since that technology is not going to be
3 here until after 2020. Or should you be looking at it today?
4 That would then spur it on and sort of like accelerate the
5 commercialization of that technology.

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

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

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

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

1 couldn't do that in the time frame we had from the scoping
2 plan.

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

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

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

23 When you do your economic analysis for how you look
24 at CCS and their options for the future, do you do option

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

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

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

24 MR. MYER: Thank you very much, Mary Jane. Most

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

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

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

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

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

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

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

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

1 is.

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

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

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

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1 renewable energy and looked at CCS as a contributing factor.

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

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

18 Well, if you thought about it from a business
19 perspective, and I was listening to some of your comments and
20 it seems that they're asking, just give us cost recovery.
21 And we shouldn't just be thinking about cost recovery for
22 projects like that. We should be thinking about giving them
23 a profit and having other companies competing with them
24 because there's an opportunity to earn some money because

1 eventually you know where you want to get and you're going to
2 have capture carbon to get there.

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

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

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

1 so forth.

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

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

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

18 UNKNOWN SPEAKER: Say it one more time.

19 MR. MYER: By all means.

20 MR. JOHNSON: And perhaps I'll share with you, I
21 guess it was mentioned earlier. And when it comes to the
22 renewable portfolio standard and the thought of going from 20
23 to 33 percent without including CCS, I guess Senator Coleman,
24 before he had all of his political problems and so forth had

1 developed a document that perhaps I'll share with you as well
2 that talks about having a clean energy portfolio standard
3 that would include CCS along with renewable energy.

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

6 MR. PERIDAS: George Peridas, NRDC. A question
7 probably for Mary Jane, just for my own benefit. Do we know
8 how emissions from petroleum coke produced at refineries are
9 treated? Because usually the fate or the (indiscernible) has
10 to be exported and combusted using the developing wells. So
11 how is that treated under either the (indiscernible) or AB
12 32? Is it outside? Or is it considered to displace coal
13 that would have been combusted instead for the production of
14 energy? How does that work? Or is it (indiscernible) part
15 of the California emissions?

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

21 MR. PERIDAS: Okay. Thank you.

22 MR. NYER: Any other questions or thoughts? I think
23 we've had a very interesting discussion today. We had some
24 multiple perspectives, particularly on such subjects as

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1 liability. So we have certainly work to do there to bring
2 any sort of consensus.

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

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

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

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

1 MR. MYER: Just -- Craig Hart.

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

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

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

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

1 They're focusing more on capture.

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

8 MR. MYER: Geir.

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

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

22 Most of the time, for these projects, my experience,
23 my personal experience with this is six years or more. And
24 if you look at the projects that have been in motion for some

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1 time, it will take more than eight years to get them set in
2 and that's after working OSPERT regulations, London
3 Convention, different directives and the likes.

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

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

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

23 And so, whatever issues need to be worked out in the
24 policy and regulatory and incentive and business and fronts

1 to make that happen, I think there is, indeed, an urgency
2 there and this forum is certainly not unique in stating that
3 need.

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

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

19 MS. RAU: Tiffany Rau, Hydrogen Energy
20 International. Yeah, I think it's a question of kind of
21 magnitude and reaching a widespread public. I think outreach
22 efforts so far have been focused on policy makers and
23 impacted communities as opposed to kind of a widespread. And
24 it's difficult to get to kind of mass public so that CCS,

1 kind of a more common concept, commonly understood
2 technology.

3 So I mean, I'm getting the point where I think it's
4 media that has to be educated, editorial boards that have to
5 be educated. It's easy to kind of throw up concerns about
6 CO2 and kind of demonize it when the facts are, for me, the
7 more you learn about it, the more you learn about CO2 and
8 capture and sequestration, the more it makes sense, the more
9 comfortable you are with it. But when you hear about it for
10 the first time, it's something that makes you take pause.

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

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

19 We have one final -- unless -- now, so I give folks
20 one final opportunity to speak their peace with regards to
21 our Workshop today. Any input? And we had one final agenda
22 item, sort of a formal agenda item specifically for comments
23 from the Department of Conservation or the PUC or CARB. If
24 there is any comments that anyone wanted to officially put

1 | into the record from those organizations, this would be the
2 | time to do that. And I see none.

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

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

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