JOINT COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Preparation of the 2009	)	Docket No.
Integrated Energy Policy Report	)	09-IEP-1K
_____	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, APRIL 15, 2009

8:30 A.M.

Reported by:
John Cota
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member,
Integrated Energy Policy Report Committee

James D. Boyd, Vice Chairman and Associate Member,
Integrated Energy Policy Report Committee and
Presiding Member, Transportation Committee

ADVISORS PRESENT

Susan Brown

Kristy Chew

Diana Schwyzer

STAFF and CONTRACTORS PRESENT

Nick Janusch

Suzanne Korosec

Gordon Schremp

ALSO PRESENT

Dileep Sirur
Baker & O'Brien, Incorporated

Bob Poole
Western States Petroleum Association (WSPA)

Evelyn Kahl
Alcantar & Kahl LLP

Rock Zierman
California Independent Petroleum Association
(CIPA)

Dominic D. Ferrari
Plains All American Pipeline, LP

Seth K. Jacobson
Center for Advanced Studies on Terrorism (CAST)

Duane Yantorno (via telephone)
Arizona Department of Weights & Measures (AZ DWM)

Steven Sokolsky
CALSTART

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

2 8:32 a.m.

3 MS. KOROSEC: Good morning, everyone.

4 Welcome to day two of this Joint Transportation

5 and IEPR Committee Workshop on transportation

6 infrastructure issues.

7 Happy Tax Day. I hope everybody got

8 their taxes done and in on time.

9 For those of you who weren't here

10 yesterday I'll just do some quick housekeeping

11 items. Restrooms are out the double doors and to

12 your left. There's a snack room on the second

13 floor at the top of the stairs under the white

14 awning. And if there is an emergency and we need

15 to evacuate the building please follow the staff

16 out the door to the park kitty-corner to the

17 building and wait there for the all-clear signal.

18 With that, and since we have such a full

19 agenda today and need to be done by noon, I'll

20 turn it over to the Commissioners for opening

21 comments.

22 PRESIDING MEMBER BYRON: Weren't we here

23 yesterday, Commissioner?

24 VICE CHAIRMAN BOYD: I slept in my

25 office, I don't know.

1 PRESIDING MEMBER BYRON: Thank you all
2 for returning for a second day on the
3 transportation fuel infrastructure issues for the
4 IEPR Committee and the Transportation Committees
5 of the Energy Commission.
6 We are very interested in this topic at
7 the Commission. It was a jam-packed agenda
8 yesterday. We assume it will be no less today. I
9 see a couple of new faces here that weren't here
10 yesterday. The fact is that there was a lot of
11 information covered. We did not have enough time
12 on the calendar so we asked our staff to make it
13 fit a day and a half. We apologize for the 8:30
14 start but that's so we can finish by noon, I
15 believe.
16 I am really not going to add anything
17 else. I would like to get through it and make
18 sure we have plenty of time for comments,
19 questions and public comment, if necessary, at the
20 end. Commissioner Boyd?
21 VICE CHAIRMAN BOYD: Ditto. I
22 appreciate everybody being here. It's a somewhat
23 different crowd. A little thinner crowd, maybe
24 some are still doing their taxes, I don't know.
25 But it's a somewhat different subject.

1 Yesterday was very interesting.
2 Although this subject has proven to be very
3 interesting, if not every year every other year.
4 And some issues persist in remaining issues and
5 unfortunately a host of new issues were introduced
6 yesterday. So I think this will prove to be very
7 productive both for the IEPR and for the ongoing
8 work of the Commission through its Transportation
9 Committee and the IEPR Committee.
10 So like you, let's get on with the show.
11 PRESIDING MEMBER BYRON: Okay. Let me
12 do one more thing.
13 With us also is Commissioner Boyd's
14 advisor, Susan Brown, all the way to my left. And
15 all the way to my right is Diana Schwyzer, the
16 Chairman, Chairman Douglas' advisor. I believe
17 Kristy Chew will be joining us shortly. I just
18 received a note from her that she is in traffic.
19 And for those of you that don't have
20 your taxes filed today I understand that the West
21 Sacramento Post Office will be open until midnight
22 tonight. Gordon.
23 MR. SCHREMP: Welcome Commissioners,
24 advisors, members of the public and industry.
25 Thank you for all appearing today. And we thank

all the people who have agreed to speak today. We know we, I think, made some requests rather recently and so we are very appreciative of all the hard that people have to go through not only to be here but to cobble together a lot of information to bring to our attention.

So once again to echo the Commissioner's comments. This is to provide information as part of our Integrated Energy Policy Report process so it is a great opportunity for you folks to raise and identify those key issues that we need to be paying attention to as part of this process. This is an information-gathering proceeding.

I will be providing some information this morning on our preliminary crude oil import forecast for California. Other speakers to follow me will have some more detailed assessments of that and other issues associated with that. And I will also talking a little bit later this morning about our pipeline export and how we forecast those exports and why that is important with regard to total load on our system. So I'll proceed here.

Every two years we also do a crude oil import forecast. We're adjusting the sound here

1 so everyone can hear me. There we go. Before I
2 forget --
3 (Feedback was heard.)
4 MR. SCHREMP: There we go. All right,
5 can you hear me now? Actually is this still
6 working? Okay.
7 Before I go on I just wanted to mention,
8 when we do have our speakers, in case I forget, we
9 are on a very tight schedule. We would appreciate
10 if you could work through your presentation within
11 10 to 15 minutes so we still allow time for
12 comments and questions. To help you with that
13 process we will be giving you a signal that you
14 have about five more minutes. So I'll be sitting
15 fairly close to you so you'll see me if I have to
16 do that. That helps us make sure everyone will
17 have an equal opportunity to make comments today.
18 So I just wanted to interrupt my presentation to
19 tell you that.
20 So crude oil production. Crude oil
21 production in the United States and in California
22 has been declining. It has been going on since
23 the peak in California in 1985 and the United
24 States in 1986. So the decline is also occurring
25 in Alaska. It peaked a little bit later but the

1 decline rate has been ever steeper in Alaska.
2 So here are the numbers and I'll go down
3 into California. A similar shape. There was an
4 up-tick in the mid-1990s as a consequence of
5 increased activity offshore in federal waters but
6 those fields have peaked. The decline was
7 somewhat rapid and has leveled off. State
8 offshore has been declining very gradually and
9 state onshore at a greater clip but it's still a
10 downward forecast.
11 So those are the trends and that's what
12 we look at to determine what the future might hold
13 for us.
14 This is a little bit longer view on
15 California crude oil production. Back into the
16 mid-1800s. Actually the data goes back to I think
17 1850. We have produced an awful lot of crude oil.
18 But if you put that in the context of global
19 demand it is not even a full year's after
20 producing crude for in excess of 100 years in
21 California, and one of the largest crude oil
22 producers certainly in the United States. So a
23 significant amount of oil but still rather small
24 in comparison to global demand.
25 Here are just some of the facts and

1 figures. I won't, I won't labor on them except to
2 point out that the crude oil production decline in
3 Alaska has been the greatest at 63 percent since
4 1986. And California was the second-largest at 41
5 percent followed by the rest of the United States,
6 absent California and Alaska numbers.
7 So we think these declines will
8 continue. The decline rate we are most concerned
9 about is the one in California because that
10 affects the load on our crude oil import
11 infrastructure.
12 This is a look at the receipts of crude
13 oil, both from Alaska and foreign. Those are
14 water-borne receipts. To us there is no
15 difference in terms of the load on the system.
16 They both have to arrive via ship.
17 So we see that there was a slight, I
18 guess a leveling off since 2005. In part that is
19 because of a decline in demand for both diesel,
20 gasoline and jet fuel in the southwest region.
21 And lower refinery runs and higher maintenance on
22 crude oil facilities. So we are, so we are not
23 surprised to see that the total load of imports
24 has sort of leveled off.
25 But you also notice that there is a

1 tremendous increase in foreign imports. And this
2 is a consequence both of Alaska's continued
3 decline. Sourcing more -- Less and less Alaska
4 crude oil coming to California. And the
5 refineries understand that trend and are looking
6 at trying different types of foreign crude oils
7 that may work and may yield a similar slate of
8 products. And so that's what has been going on.
9 And when they discover new sources that
10 they can lock into longer term rates they will do
11 that and they will start bringing it in and
12 replacing that Alaska crude oil which is going
13 away anyway. So there is no surprise in seeing
14 the increase in foreign imports. But the
15 difference is there is still a load on the system
16 and that's the concern moving forward.
17 So as I mentioned Alaska is down quite a
18 bit and foreign is up. We are expecting that
19 foreign imports will continue to rise in
20 California but we are expecting the total amount
21 of imports to rise.
22 So what do we look at? We look at two
23 factors. One is, what is the decline rat in the
24 California fields. So whatever less crude oil is
25 produced would have to be brought in over the

1 water.

2 Number two is, are the refineries

3 processing greater quantities of crude oil over

4 time in their crude oil distillation unit? So

5 that's, we call that capacity. And over time we

6 have seen that gradually rise. Both the capacity.

7 And then the final component is, what is

8 the utilization rate? Are they running at 100

9 percent all the time? Of course they are not

10 because they are performing routine maintenance

11 every year. And larger maintenance on crude units

12 at greater intervals and we see unplanned outages

13 that do occur. So their utilization rates will

14 never be at 100 percent, they will be at some

15 lower figure. And I'll talk about that right now.

16 Utilization rates since 1990 through

17 2008 has been just a little bit under 90 percent.

18 In recent years you see a dropping down to even

19 below 86 percent. And so this is, you know, lower

20 than historical numbers but I am not surprised

21 because of the great amount of crude oil unit

22 maintenance that was going on in 2007, and a

23 downturn in demand that resulted in some

24 refineries running at lower rates than they would

25 have otherwise.

1 So this is not a surprise but we have to
2 make an assumption moving forward on what the
3 utilization rates are.
4 VICE CHAIRMAN BOYD: Gordon?
5 MR. SCHREMP: Yes.
6 VICE CHAIRMAN BOYD: How long can, in
7 your opinion, can the California refineries be
8 sustained at that low utilization rate before
9 something happens? Something topples the least
10 efficient refinery or something falls off the
11 slate. The table I should say, slate has another
12 connotation in the oil world.
13 MR. SCHREMP: A good question,
14 Commissioner. The most important factor not on
15 the screen is what are their, what are their
16 margins and ultimately what are their profit
17 levels that are occurring. And that is contingent
18 upon what the market-clearing prices may be at the
19 wholesale level for the products they are selling.
20 All the, all the clean fuels as well as residual
21 fuel oil, things like that, and what their costs
22 are.
23 So we look at refining margins, both in,
24 you know, different parts of the world, the United
25 States and in California. In California, on

1 average, the refining margins are better than that
2 in the United States, which are higher than that
3 most places in the world. So it is still a very
4 good location for profitability in terms of
5 refinery operations.
6 So even though their crude rates may be
7 lower and some of the refineries that may not have
8 supply obligations, contractual obligations for
9 almost everything they produce. That are some
10 refineries that operate more on a merchant manner.
11 They'll sell under the unbranded market and
12 they'll have contractual obligations.
13 Well, we have seen refineries like that
14 scale back their crude runs to sort of more
15 balance out supply and demand and less imports.
16 And then the market comes back into equilibrium,
17 usually at a little bit higher market clearing
18 price than it has been when it was oversupplied.
19 So the long-winded answer is, you can
20 run at lower utilization rates, assuming that you
21 are still maintaining some degree of refinery
22 profitability, especially greater than that of
23 some other regions.
24 But I don't know -- I know there was
25 some discussion yesterday about on average in the

1 United States the utilization rate being at 76
2 percent in the long-term by EIA, which is below
3 the bottom of this, the axis on this graph, for
4 all of the refiners. That's rather low. And I
5 would agree that in that context some of the
6 higher cost producing refineries will go out of
7 business if that's the case.
8 Not only that, we are seeing a large
9 increase in refining capacity in the world.
10 India's refinery, Reliance, doubled in size. Now
11 they are at 600,000 barrels a day on the
12 marketplace in May of this year. There's probably
13 another 2.5 million barrels of refining capacity
14 coming online over the next couple of years. This
15 will be a lot of product on the market which will,
16 you know, be an additional amount of competition
17 and affect market clearing prices so we'll see how
18 this plays out.
19 But running at lower rates doesn't mean
20 you are not going to be profitable, there are
21 other factors involved. So they can run at lower
22 utilization rates. As you are aware, we do have a
23 refinery that is not operating right now. Flying
24 J filed Chapter 11 on December 22 of last year and
25 their Bakersfield facility is not operating at

1 this time. So we have already seen a decrease in
2 overall refining capacity in California as a
3 consequence of that action but we anticipate that
4 being temporary in nature as part of the business
5 cycle.
6 VICE CHAIRMAN BOYD: Thank you. That
7 was a very thorough answer but you did open
8 another door that I won't pursue very far. You
9 kind of gave some people food for thought with
10 regard to why California prices at the pump tend
11 to be seemingly a little higher than perhaps logic
12 would dictate it would be as compared to prices
13 elsewhere. So in any event, I'll let that lie for
14 now.
15 MR. SCHREMP: Okay. So looking at two
16 different decline rates. Sort of a low decline
17 rate, which is the upper dotted yellow line of 2.2
18 percent per year. And that's the most recent 2006
19 through 2008 decline rate per annum average. Over
20 a longer period of time, going back to 1998, we
21 see a bit steeper decline rate of 3.2 percent per
22 year.
23 No surprise that more recently the
24 decline rate has been lessening a bit. There has
25 been some up-tick in drilling activity. There is

1 certainly a great deal of drilling activity,
2 especially when crude oil prices were in excess of
3 $100 last year but that has tumbled down.
4 The decline rate still continues even
5 with a very, you know, a very high level of crude
6 oil prices and increased drilling activity, which
7 is the nature of older, mature crude oil fields.
8 Even with an extensive amount of enhanced oil
9 recovery through injection of steam, carbon
10 dioxide and water and steam flooding.
11 So we look at the decline rates and then
12 we look at what is the utilization rate and the
13 refinery creep. So combining those two together
14 the lower line is the continued decline of
15 California-sourced crude. The upper line is the
16 refinery input, the actual input.
17 So we are assuming that utilization
18 rates will be at 90 percent over the forecast
19 period and we are assuming in this projection the
20 low forecast rate of 2.2 percent for the crude oil
21 production. So that yields increases in
22 incremental imports of crude oil over the water
23 between, you know, -- what do we have, 78 million
24 barrels ten years out from now and approximately
25 147 million 20 years out. And most of that,

1 between 60 and 70 percent, is due primarily to the
2 decline in crude oil rates, not the refinery
3 expansion.
4 Change the assumptions I change my
5 answer. A steeper decline rate on production of
6 3.2 percent and a more, I guess a more aggressive
7 refinery creep of almost .9 percent a year. The
8 previous slide was about half a percent per year.
9 And so we see that the imports do expand
10 significantly. And I'll go to --
11 VICE CHAIRMAN BOYD: Gordon?
12 MR. SCHREMP: Yes.
13 VICE CHAIRMAN BOYD: Sorry to interrupt
14 you again. But harking back to yesterday's
15 discussion of the status of import facilities,
16 marine terminals, et cetera, et cetera. Are we
17 presently equipped to handle that amount of
18 import?
19 MR. SCHREMP: At this time -- well, time
20 is all relative. In the near- to mid-term the
21 answer to that is, no. Assuming no additional
22 capacity is constructed.
23 There will be somebody here from Plains
24 All American that will be discussing their
25 project. They have been before you one, two,

1 three IEPR cycles. And they will talk about --
2 VICE CHAIRMAN BOYD: Yes, I'm aging as
3 that project ages.
4 MR. SCHREMP: So we have -- Staff has
5 assumed that if in fact that project in Southern
6 California is constructed the additional load we
7 are anticipating for Southern California will be
8 met by the construction of that facility for crude
9 oil, so that won't be a problem.
10 Northern California, we will be
11 examining that in this IEPR cycle and be providing
12 some analysis. We have not yet completed that
13 work. But the need is growing a bit more
14 gradually in Northern California and there are
15 some other resupply options that may include
16 barrels imported through Southern California and
17 piped all the way up to Northern California.
18 VICE CHAIRMAN BOYD: Thank you.
19 MR. SCHREMP: So we'll be getting to
20 that.
21 VICE CHAIRMAN BOYD: Mr. IEPR Chairman,
22 there's a subject for the IEPR.
23 PRESIDING MEMBER BYRON: Gordon, another
24 quick question if I may. These two forecasts for
25 both the low and the high obviously show a decline

in California production. But yet we have heard recent reports and had briefings on shale gas. Is there any of that in California? Will fracturing technology and lateral drilling affect, potentially affect production here in California?

MR. SCHREMP: That's primarily with natural gas.

PRESIDING MEMBER BYRON: I'm so sorry.

MR. SCHREMP: No, no.

PRESIDING MEMBER BYRON: You're absolutely right.

MR. SCHREMP: But your question is spot on in terms of, are there some additional technology or resource potential that could affect these forecast trend lines? Yes. And that has to do with, I believe some of the speakers will address this. Is, are there some resources near shore? Offshore resources that can be got at through, say, directional drilling from onshore and expansion of offshore drilling, which certainly has been controversial.

So the answer is yes, these decline rates can not only be halted but can in fact be reversed. But it has to do with access to resources, timing of that work and the economics

of trying to develop those resources. But it takes an awful long period of time. We have estimated between seven to ten years once that whole process starts.

The lease process, just developing that lease. Putting it out for bid and then developing the work is an extremely long process. So even if in fact one were to pursue that in California it wouldn't be something that would occur next year or even five years from now. So it would take a great deal of time to come to -- But I think people are going to address some of that, some of those issues after I do.

PRESIDING MEMBER BYRON: All right, thank you.

MR. SCHREMP: Those are just the numbers we used so you have that in your presentation. I'll just jump right to the slide. These are the incremental barrels. And you 405 million barrels was the 2008 import level for the year. So you can compare those to the 405 and you see that there is anywhere from a 19 to 36 percent by 2018 and 31 to 58 percent by 2028.

So we still expect Southern California to receive the lion's share of these imports, at

1 least 60 percent. And I believe Dileep Sirur will
2 be addressing that issue after, after I'm done
3 speaking. So I just want to point out once again,
4 reiterate that the majority of these incremental
5 imports are primarily because of a declining, a
6 continued declining rate of production in
7 California, 60 to 70 percent of those barrels.
8 So here are some of the issues that we
9 would like to get answers to as part of this
10 information-gathering process that we believe we
11 have to address at a minimum.
12 You know, what technology, what
13 resources may change those assumptions on the
14 decline rates? What other regulations may impact
15 operations both in the crude oil producing
16 facilities -- fields because they use an awful lot
17 of energy, hence oil recovery.
18 And how might refineries be impacted?
19 We are assuming continued growth in distillation
20 capacity. Are there regulations such as AB 32
21 that could affect those operations. Are there
22 economic reasons that may cause refineries not to
23 continue expanding like that. So we would like
24 input on all of this as part of these proceedings.
25 Here are the speakers who will follow me

1 in this first session on crude oil infrastructure.
2 If there aren't any additional questions I'd be
3 happy to have Dileep Sirur step up. Thank you.
4 MR. SIRUR: Good morning, Commissioners,
5 advisors, members of the audience. I was here a
6 couple of years ago, two years ago, to talk about
7 -- I'm sorry, I'm Dileep Sirur, I'm with Baker and
8 O'Brien, a consulting firm in Dallas. And I'm
9 here on behalf of Plains All American Pipeline.
10 PRESIDING MEMBER BYRON: Welcome.
11 MR. SIRUR: Thank you.
12 I was here a couple of years ago to talk
13 about the outlook for Southern California with
14 respect to its crude supply. And given all the
15 changes that we have seen in the environment, the
16 most recent changes, Gordon invited us to come by
17 and present an update of what we had presented two
18 years ago. And there are some significant changes
19 which we will go through. But there are other
20 items which haven't changed; we'll talk about that
21 as well.
22 Well since our last assessment, as you
23 will see, in the last year we have had the real
24 estate crisis and the world financial crisis. A
25 deep recession here and all over the world.

1 And a steep decline in demand for
2 petroleum products in the US.
3 And a slight reduction in refinery runs,
4 but significant reduction in imported products.
5 And specifically with respect to
6 Southern California, we had forecast a substantial
7 increase over the 2006 run for 2008 when we were
8 here last time from levels of about 2005 -- I'm
9 sorry, 500,000 barrels a day to about 625,000
10 barrels a day. But the imports actually fell in
11 2007 and 2008. They went back to the 2006 levels
12 so we are back where we started.
13 And the other things are federal
14 legislation, which I really won't go through in
15 great detail because I think it was talked about
16 at length yesterday. It's the EISA act of 2007.
17 And I think all of you know what the issues are on
18 that.
19 And of course in California itself it's
20 the Amended CARB 3 model, which was talked about
21 at length yesterday. Where you would see an
22 increase of ethanol content going up to ten
23 percent.
24 And then the bill AB 32 with respect to
25 greenhouse gas emissions.

1 And then one other one I saw there was
2 the greenhouse gas cap and trade. The Western
3 Climate Initiative which comprised California,
4 four other western states and two western Canadian
5 provinces. It coordinates with AB 32. Its
6 objective being to keep reduced greenhouse gas
7 emissions to 15 percent below 2005 levels by the
8 year 2020.
9 All of these, clearly as enacted, would
10 put a damper on the amount of petroleum-based
11 refined products that would be acquired.
12 Now I want to go through the key
13 assumptions that we used for going through our
14 analysis and I'll show you the results after that.
15 I'll start with the crude oil. ANS crude oil,
16 2008 product was 700,000 barrels a day. But we
17 had predicted that -- two years ago we had
18 predicted that to be about 750,000 barrels a day.
19 So the last projection that we have gotten from
20 the state of Alaska, really the numbers are well
21 below what was projected.
22 And the most recent projection gives you
23 about 2.1 percent a year reduction through 2023.
24 We have taken a 15 year span. And again like I
25 said, it came from the state of Alaska. In a

1 previous assessment the rate was faster, about 2.5
2 percent or thereabouts. But it really didn't have
3 much of an effect because we are starting now from
4 a lower number. So we already declined some it
5 doesn't have much of an effect on an overall
6 answer.
7 Now the way we distributed the ANS was
8 identical to what we had done two years ago. We
9 first applied it to Alaska refineries and Pacific
10 Northwest refineries. Recognizing that those
11 regions needed these crudes for a variety of
12 reasons. Most of Alaska's crude is run in inland
13 refineries. They have no alternative. And the
14 Puget Sound refineries don't have access to many
15 imports because of the port restrictions.
16 And Hawaii used to get about 100,000
17 barrels a day. We don't see anything going there
18 in the future. It's not going there now.
19 VICE CHAIRMAN BOYD: Could I ask you a
20 question about the decline in ANS crude.
21 MR. SIRUR: Yes sir.
22 VICE CHAIRMAN BOYD: Everybody has known
23 that was inevitable, it was going to occur over
24 time. I'm just wondering if the current figures
25 documenting the declining production take into

1 account any technological efforts to increase
2 yield? We're pretty ingenious technologists and
3 over time find new ways of squeezing more through
4 technology out of wells. Is that going on in
5 Alaska?
6 MR. SIRUR: While I haven't studied this
7 in detail the forecast, as I saw the forecast as I
8 put this together, they have incorporated these
9 improved technologies going to -- and then
10 recovering some of the heavier crudes which were,
11 which were considered impossible to recover some
12 years ago. And they have put certain
13 probabilities which we incorporated in there. So
14 yes, I think the answer to your question is yes,
15 that's been incorporated in the forecast as well.
16 VICE CHAIRMAN BOYD: Thank you.
17 MR. SIRUR: Now the balance of the crude
18 then goes to California. And the way we have
19 divided between Northern and Southern California,
20 we have given more to Northern California,
21 recognizing that Southern California is already
22 kind of moving away from ANS much faster than
23 Northern California is.
24 Now with respect to California crude.
25 Two years ago we said it would decline at 3.5

1 percent a year and that we have not changed. And
2 our rationale is relatively simple. For the last
3 five years it's declined at the rate of about 3.3
4 percent a year in a generally rising price
5 environment. So given that we felt that there was
6 not much justification for changing from the 3.5
7 percent level that we had before.
8 And the way we distributed the crude was
9 first send it to Bakersfield and Santa Maria area
10 refineries, which do not have access to foreign
11 crudes. And then we also assumed, this is another
12 point, the Flying J refinery which we just talked
13 about, or some proxy, which meant that some other
14 refinery would pick up this capacity if you will.
15 Not one other refinery but several of the other
16 refineries would take this capacity on an
17 incremental. We assumed that would restart by the
18 end of next year or by 2010.
19 VICE CHAIRMAN BOYD: So the assumption
20 is none of that oil will be stranded in the area.
21 MR. SIRUR: That's right.
22 And then again we move the oil to
23 Northern and Southern California. And recognizing
24 the marine logistics in Southern California we
25 preferentially move the crude to the north and

1 then the balance went to the south.
2 Now this is where we made some
3 significant changes in refinery runs. In our last
4 assessment we had assumed a 1.25 percent increase
5 in refinery runs, or a creep if you will, for the
6 15 years that we had there. And in addition to
7 that we assumed that one of the refiners would add
8 50,000 barrels a day of capacity in 2012.
9 And I think it's pretty clear to us now
10 that these assumptions are really not likely to be
11 realistic in the current market and economic
12 environment that we are in. So rather than try to
13 predict something where things are so fluid we
14 decided to look at three alternative scenarios for
15 the next 15 years, which is from 2009 to 2023.
16 The first thing we did, we eliminated
17 that extra 50,000 barrels a day capacity. We just
18 I think felt that in this environment or into the
19 foreseeable short-term future you are not going to
20 see additions of capacity.
21 And then we hanged the refinery run
22 increases. And we looked at three scenarios. The
23 first scenario, we said for all 15 years it would
24 increase at one percent a year. We called that
25 Scenario A.

1 And then Scenario B, we went to one
2 percent a year for the first five years, half a
3 percent a year for the next five years, and no
4 increase for the last five years. Kind of
5 recognizing that some of these rulings that we
6 talked about would start phasing in around those
7 periods. Around the latter part of this time
8 horizon.
9 And then the third one, which is just a
10 variation I believe, of B, was that we kept the
11 one percent a year for the first half and reduced
12 it to zero for the second half.
13 Now on the next slide here I have a --
14 I'm sorry, I need to talk about crude oil imports,
15 how we managed the crude oil imports analysis.
16 Right now the imports are coming from
17 the Middle East, Latin America, West Africa and
18 some amounts are coming from the Pacific Rim and
19 Canada.
20 And what we did was we maintained the
21 current levels of imports and just escalated them
22 for the refinery run increases to keep, to kind of
23 maintain the current levels and not change them.
24 But then the increasing reductions in
25 ANS and California crudes made up additional

1 imports.
2 ANS was generally substituted for with
3 similar quality, they typically tend to be
4 somewhat higher in sulphur Middle East crudes.
5 California, we replaced them with a
6 combination of heavier crude oils which were from
7 Latin America, West Africa and some from the
8 Middle East.
9 And then just a note here. The
10 incremental Canadian crudes, which are really the
11 oil sands bitumen crudes that are being produced
12 now. We expect to see -- we said we would expect
13 to see some by 2016 pipelined from a deepwater
14 port in Northern British Columbia.
15 Now there's a lot of controversy out
16 there. I think things have slowed down in Canada
17 because of today's prices. The availability of
18 this crude, because it needs a pipeline, is, you
19 know, is kind of questionable. But then if that
20 weren't available some other crude like Nigerian
21 crude or Latin American crudes would be required.
22 And finally, West African crudes would
23 also increase. And these would be low-sulphur,
24 heavy crudes. And the word, I think, high TAN, is
25 just very acidic crudes which don't have an easy

1 market but could do well as a substitute for
2 California crudes, which also have the high TAN.
3 I'll go through this real quickly but
4 this is -- if you looked at Scenario A we have
5 history through 2008 and then the future to 2023.
6 We have orange is imports and green is ANS and
7 blue is California. This is for the Scenario A.
8 And the runs go up to about 1.1 million barrels a
9 day and the imports are around 1 million barrels a
10 day.
11 I've got a few more slides later that
12 will show the imports more clearly so I'll just
13 show you the next two very quickly for Scenario B,
14 which gives you a slightly lower 2023 run rate and
15 corresponding lower import rate.
16 VICE CHAIRMAN BOYD: Could I ask a
17 question. Do your projections for the future take
18 into account any estimate of the penetration of
19 alternative fuels into the --
20 MR. SIRUR: In a way they do. We are
21 believing I think if it wasn't for the alternative
22 fuels we wouldn't have gone up this slowly.
23 Particularly towards the latter part we are
24 flattening out our refinery runs. That I think is
25 recognition of alternative fuels, clearly.

1 Now this I think is more, I think I want
2 to spend a little time on these three charts. The
3 first one shows, the first bar is for what we have
4 in 2008; the next bars are for 2013 for Scenario
5 A, B and C. These are identical for 2013 because
6 all of them are for the -- all three of them have
7 one percent a year through 2013.
8 But as you go later in the period. When
9 you go to 2018 the increase becomes much better
10 defined. And you can see there the differences
11 between Scenario A, which is among the three more
12 aggressive, and Scenario C is the least aggressive
13 or more conservative. But one of the things you
14 see here is that imports continue to be dominated
15 by the Middle East and Latin American, that does
16 not change.
17 And then we go to 2023 for the same
18 slide. And again you see Scenario A is having
19 about a million barrels a day imports and Scenario
20 B and C having a little over 900,000, 950,000
21 barrels a day of imports. Compared to about
22 500,000 barrels a day in 2008. And you still see
23 domination by the Middle East and Latin America.
24 This next slide is -- it looks like the
25 same as the others and it isn't. I was talking

1 about a 2007 assessment. So this is for the year
2 2023. The first column is what we -- our
3 assessment in 2007 which I presented to you two
4 years ago. And I compared that for the same year
5 with Scenario A, B and C. And you will see that
6 there is about a 200,000 barrel a day import
7 difference between the 2007 assessment and
8 Scenario A. And another 50,000 or so more for
9 Scenarios B and C.
10 So that's where you see the key
11 difference with all the input changes that we
12 made. In the last year where we were -- in the
13 last two years where we assumed a zero growth of
14 refinery rates. That's where you see the very,
15 distinctly see the difference.
16 But one thing. With all the, with all
17 the different scenarios that we have looked at
18 it's pretty clear. The reason why we still have a
19 significant need for imports is because of the
20 decline of California and ANS crudes. Which
21 really the perception of those declines hasn't
22 changed.
23 I'll go through this pretty quickly.
24 This is just what we observed from what I have
25 shown you in the bar charts. And these

1 conclusions have been dampened but haven't been
2 changed since the, since my 2007 presentation.
3 I think by the end of this forecast
4 period the Southern California supply will be
5 dominated by imports.
6 Imports, depending on which scenario we
7 have, will be between 900,000 to a million barrels
8 a day, which is roughly 80 to 90 percent of total
9 crude oil runs.
10 And this is compared to half a million
11 barrels a day, which is 50 percent of total crude
12 oil runs.
13 The Middle East will be the primary
14 source. About half a million barrels a day or 50
15 percent of crude oil runs.
16 And the import of Canadian crudes will
17 increase to about 70,000 to 80,000 barrels a day
18 starting in 2015. Earlier we had said it would
19 start in about 2012 or so but I don't think that's
20 in the cards.
21 West African crude will continue to
22 increase to levels of about 130,000 barrels a day.
23 Latin American crude imports, again,
24 from today's 200,000 barrels a day will increase
25 to about 260,000 barrels a day or so.

1 And Pacific Rim has been very minimal
2 and that will, that will stay that way.
3 VICE CHAIRMAN BOYD: I can barely
4 discern the red line on your chart.
5 MR. SIRUR: That's right. I think we
6 should have had a, I think we may have missed some
7 of the red lines. Because I saw one but --
8 ADVISOR BROWN: I have a question.
9 MR. SIRUR: Yes.
10 ADVISOR BROWN: Excuse me. Just on the
11 first bullet. I'm assuming that you mean oil
12 sands when you estimate Canadian oil imports.
13 MR. SIRUR: That's right. When I said
14 "new" I meant oil sands, yes.
15 VICE CHAIRMAN BOYD: Can I ask you.
16 Latin American imports. Do you have that dis-
17 aggregated in any way to various source points?
18 MR. SIRUR: Historically we do. And we
19 are looking at -- at this point, I mean, if we
20 look at what is happening today. There is a
21 considerable amount of oil coming from Ecuador.
22 There are two grades there. One is called Napo --
23 One is called Oriente, which is somewhat lighter
24 but it is still quite heavy. And then they have
25 got a new grade called Napo which is 20 API and

1 relatively low in sulphur. It's about two percent
2 sulfur.
3 Those are the two crudes that have
4 dominated recently along with Mexican Maya crude,
5 which is 20 API and quite high in sulphur, 3.5
6 percent. But just a few months ago the Mexicans
7 have been, their production has been going down
8 rapidly. They stopped shipping to the, they
9 stopped shipping to the West Coast. And even the,
10 even the Gulf Coast refineries are having problems
11 with getting their allocations.
12 Another crude that is starting to show
13 up in considerable volumes is a Brazilian heavy
14 crude. Marlim (phonetic) is the name of that
15 crude. And that's about one percent and 19 API.
16 And it's highly, it's quite acidic so it would fit
17 very well and does fit very well in, on the West
18 Coast. Chevron I believe has been bringing
19 considerable amounts of that into that their
20 refinery.
21 VICE CHAIRMAN BOYD: Thank you.
22 MR. SIRUR: So that concludes, concludes
23 my presentation and I'll be happy to answer any
24 more questions.
25 VICE CHAIRMAN BOYD: I have no

1 questions, maybe a statement. The last bullet on
2 your next to the last slide about the Middle East
3 being the primary source of total crude imports.
4 And that's pretty well dominated many of your
5 projections.
6 MR. SIRUR: Right.
7 VICE CHAIRMAN BOYD: I would, I would
8 just say I guess that that's a problem for this
9 country and that's a challenge that we have to
10 deal with. It's an economic problem and an
11 economic challenge.
12 MR. SIRUR: And I think the real
13 problem, there is, there is so much of it there.
14 VICE CHAIRMAN BOYD: Right.
15 MR. SIRUR: The production is dominated
16 by Middle Eastern crude. And even -- Of course
17 the ANS, ANS now is a 30 API, one percent sulphur
18 crude. And if you look around there are very few
19 animals that look like that. So you just about
20 have to bring in some relatively light Middle
21 Eastern crudes which have higher sulphur so that
22 you don't disrupt the operation of the refinery
23 but you have to make arrangements to remove the
24 sulphur from it.
25 If you look at Chevron's imports, for

1 example. Chevron used to run a lot of ANS. Which
2 if you look at the total, if you just estimated
3 total runs and then see how imports they are
4 bringing right now you could see that their ANS
5 has been going down dramatically. At one point I
6 think they virtually ran all ANS and now they are
7 running less than -- significantly less, let's put
8 it that way. But they have put in a lot of
9 sulphur recovery equipment to do that.
10 VICE CHAIRMAN BOYD: Thank you.
11 PRESIDING MEMBER BYRON: Thank you very
12 much.
13 MR. SIRUR: Thank you.
14 MR. SCHREMP: Thank you, Dileep.
15 We have Bob Poole who is here from WSPA.
16 He is going to provide us with some additional
17 information. One of the questions you had was
18 potentially other resources that may be available
19 that could affect the decline rate assumptions.
20 He'll be talking about that. And then I guess
21 Evelyn Kahl will be on deck.
22 MR. POOLE: Good morning, Commissioners,
23 advisors. Thank you for this opportunity. As
24 Gordon said my name is Bob Poole. I am a senior
25 coordinator for Western States Petroleum

1 Association. And I know my boss, Joe Sparano,
2 spoke to you yesterday and is a regular
3 commentator here.
4 One of the things I deal with are the
5 offshore issues, the regulations relative to the
6 platforms. A lot of the coastal issues,
7 production upstream, and also marine issues. So
8 I'm here to talk a little bit about in terms of
9 addressing the energy adequacy issues in terms of
10 transportation fuels. Talk a little bit about
11 access infrastructure and the current existing
12 technology and opportunities that we have in the
13 offshore environment here.
14 Now in terms of -- Commissioner Boyd,
15 you mentioned about the Middle East crude being a
16 problem. I would suggest here that we do have
17 reserves offshore, our own country. And that --
18 or the main challenges for us to bring forward is
19 access to those resources.
20 VICE CHAIRMAN BOYD: My, did I give you
21 an opening.
22 MR. POOLE: Yes you did, sir. I hope
23 you don't mind I used it.
24 VICE CHAIRMAN BOYD: I would expect so.
25 MR. POOLE: Yesterday my boss spoke in

1 terms of that the future will require multiple
2 sources and strategies. Along those lines my talk
3 is going to key in on domestic supplies through
4 greater access, obviously. It is also going to
5 talk about the existing infrastructure, both
6 offshore and onshore related to offshore that
7 supports that. The current state of the
8 technology that's being deployed and that can be
9 used to enhance the recovery of the existing
10 resources. And then I'll finish with just a
11 little brief underscore on AB 32 implementation.
12 Now here is a little more drilled down,
13 if you'll pardon the pun, look at the resources
14 off of California. As most of you know most of
15 them are off the coast of Santa Barbara County,
16 both on the Santa Maria Basin up by Point Sal and
17 then down below in the Santa Barbara Channel.
18 There are also some other areas of production and
19 what I would like to do is go through and show you
20 those here briefly.
21 But first I would like you to know that
22 there are 23 platforms offshore in federal waters,
23 that's beyond three miles, and there are four
24 platforms operating within the three mile limit,
25 three of which are off the LA Basin, I'll show you

1 a map on that, and one off of the coast of Santa
2 Barbara, Platform Holly.
3 Here are three different maps form the
4 Minerals Management Service that gives you a
5 little better understanding of the infrastructure.
6 The platforms that are offshore, the various
7 pipelines that are bringing those products to
8 shore. All the power that's, these platforms have
9 all basically been electrified to reduce emissions
10 so there's a lot of, there are power cables back
11 and forth on those.
12 So the structure in the San Pedro Bay.
13 You can see there are a number of platforms, both
14 in the federal waters and in the state waters and
15 then some onshore facilities.
16 The image in the middle there, Santa
17 Barbara Channel, is where the majority of the
18 platforms are. The Ventura Field extends offshore
19 kind of at a diagonal and those platforms are for
20 the most part seeded over top of that offshore
21 reserve of the Ventura Field.
22 And then going up around the corner in
23 the Santa Maria Basin. You can see there are a
24 number of platforms. The highest platform is
25 Platform Irene, which is our northernmost

1 platform. And that's just off Vandenberg Air
2 Force Base.
3 There are also five man-made islands
4 that are being used in the production of offshore
5 crude, four of which are contained in what is
6 called the THUMBS area down by the Queen Mary off
7 the City of Long Beach. There is a joint effort
8 between the City of Long Beach and the state of
9 California. Occidental operates that on behalf of
10 the City of Long Beach and that's where four of
11 them are. Here are two of those four.
12 And then the fifth one occurs just on
13 the northern boundary of Ventura County. You may
14 have seen it driving up and down the coast.
15 Rincon Island, there's another production facility
16 as well.
17 Now here is kind of a more expanded
18 version of the operations, the infrastructure
19 that's in place right in Santa Barbara County. If
20 you take a look offshore, the squares there if you
21 will, the light blue squares, the little
22 platforms. Those are active leases, units, fields
23 being produced. The white squares are leases that
24 have been put forward but are for the most part
25 currently in litigation. There are some other

1 opportunities there.
2 But if you take a look at the squares
3 that's basically where the oil is, relating back
4 to the previous slide that I showed you. And then
5 you can see the platforms. You can see the little
6 red lines, the pipelines coming onshore. There's
7 a whole structure of pipelines carrying product,
8 both to onshore processing facilities where a
9 variety of things happen such as the removal of
10 sulphur, heating up the oil to move it on beyond
11 the platforms.
12 There is some refining capacity. And
13 then transporting the oil to the other refinery
14 centers, both in Northern and Southern California.
15 So we have a comprehensive, very complex yet, very
16 functioning infrastructure that relates to the
17 production of the offshore reserves.
18 I'd like to talk a little bit about
19 technology right now in terms of the support of
20 that. What you see here is a schematic of a, I
21 guess, finished wellhead. It also shows the sub-
22 surface casing, et cetera.
23 The basic point I wanted to show you
24 here is there's redundant system upon redundant
25 system, including the various layers of casing and

1 cement going all the way down in this, in this
2 particular instance to over 6,000 feet below the
3 surface of the ocean, below the bottom of the
4 ocean. On top of that you have got a variety of
5 pressure valves, blowout prevention, shut down
6 mechanisms. This is the technology that is in
7 place in all the offshore platforms today.
8 In addition some of the applications of
9 technology to both reduce the footprint, which
10 I'll show you a slide on that in just a moment. I
11 just wanted to run down through a checklist.
12 Measurement-while-drilling technology.
13 There are actually computer components in the
14 drill heads themselves that allow them as they are
15 searching to know if they hit a high pressure
16 area. Also to direct the drill in directional
17 drilling, which I'll talk about in just a minute.
18 Global positioning systems to also give
19 the feedback as to trying to aid in the recovery
20 of those reserves.
21 High resolution inspection and
22 monitoring devices.
23 Remotely operated underwater vehicles.
24 And what you see here is an image of 3-D
25 seismic technology in terms of trying to find the

resources.

Now since 1970 there's been over a billion barrels produced off the coast of California.

There's been less 850 barrels accidently spilled.

There's currently 55,000 barrels a year seeping off the Santa Barbara Channel from natural seeps.

Here's a little slide that speaks back to the technology plus in terms of infrastructure. As you can see, the platform to your left is a fixed leg platform. All of the platforms off the coast of California are fixed leg platforms. However, you can also see demonstrated here a whole variety of other technologies that are being used around the world and that could possibly be available for us to consider as compared to sitting in a fixed leg platform.

In terms of footprint. This diagram is -- starting in 1970 you can see that the above-ground drill size approximately 20 acres and it would exploit an area below the surface of less than a square mile. That has been evolved now to where we have a 2 acre above-surface imprint with

1 an 80 square mile capability. So considerably
2 less in terms of a footprint.
3 Pardon this slide but I think it
4 illustrates the point. Directional drilling, you
5 are probably familiar with that. It is a very
6 involved technology. I think the record somewhere
7 is between seven and eight miles right now to the
8 accuracy of a cubic meter, I believe. It used to
9 be a hall closet they referred to it but it has
10 gotten even better.
11 But those all of those various
12 technologies I was telling you before, and a lot
13 more evolved drilling technology, we have options
14 to be able to go after resources from existing
15 platforms and also to have those resources
16 extracted from shore in terms of directional
17 drilling out to the reservoir.
18 Now getting back to the issue of access
19 in terms of the status of our current policies.
20 As I'm sure you are aware California has a
21 moratoria on offshore drilling within the state
22 waters.
23 There were two provisions within that
24 legislation, AB 2444, that allowed for projects,
25 two particular instances where projects could go

1 forward. One of them was the production of a
2 reservoir in state waters from an existing federal
3 platform. And you may know one of the oil
4 companies recently had a project go through to the
5 State Lands Commission where it was turned down.
6 But that was a provision that was allowed within
7 the moratoria structure of California.
8 There is also another exception and that
9 would be full field development of an existing
10 lease. There is a project currently going forward
11 with that off of Platform Holly. So even given
12 the California moratoria structure there are some
13 opportunities right now that are being brought
14 forward.
15 You may know tomorrow Secretary Salazar,
16 the Secretary of the Interior, will be speaking
17 and there will be a workshop over in San
18 Francisco. The federal moratoria, which was
19 lifted I believe in July of this last year, the
20 Minerals Management Service has moved forward with
21 their regular five-year plan. This one in the
22 instance of the 2010-2015.
23 And in that plan, which will be
24 discussed, input will be received tomorrow in San
25 Francisco, there are options in the plan for

1 leases in California off the coast of Santa
2 Barbara. This little diagram was taken out of the
3 proposed five-year plan to show you that there are
4 some other opportunities in that regard.
5 I think to recap, it's all about access.
6 I think that some of the other, of the earlier
7 comments reinforced this.
8 Eighty percent of our US energy through
9 2030 is going to come from fossil fuels.
10 Our dependence on foreign oil, as you
11 know, is projected to increase.
12 Domestic resources needed to reduce
13 imports are available.
14 The infrastructure and the technology
15 exists to increase that production in
16 environmentally safe and sensitive ways.
17 And WSPA thinks the prudent development
18 of these resources is an essential component of
19 meeting California's energy needs, now and into
20 the future.
21 And I'd like a quick, just to make a
22 quick comment about AB 32. Clearly the
23 implementation of AB 32 is very comprehensive and
24 very complex, especially with regard to the
25 petroleum industry. And from the upstream side I

1 just wanted to touch on a couple of issues today
2 briefly.
3 And then we would appreciate the
4 opportunity to further discuss some of our
5 concerns related to the implementation of AB 32
6 and how it could potentially affect the
7 infrastructure and the adequacy of our fuel
8 supply. But WSPA has been engaged for quite some
9 time, and will continue to be, with the AB 32
10 issues and implementation to try to make sure we
11 get it right, there's a lot at stake.
12 And a couple of the issues that we are
13 working on the upstream side. In terms of the
14 scoping plan, to try to establish the emissions
15 inventory on the production facilities. We have
16 been working very closely with CARB staff on that,
17 we continue to do that.
18 And then one of the other issues of
19 concern is where you have a -- in terms of energy
20 efficiency we have a co-benefit. You may be
21 reducing criteria pollutants at the same time you
22 may be reducing greenhouse gas. And so in terms
23 of making sure we get that right so that we get
24 the co-benefit, I guess, is just a simple way to
25 say that.

1 I think that concludes my presentation.
2 I'd be glad to answer any questions if I'm able.
3 ADVISOR BROWN: Can you expound upon the
4 federal moratorium lifting and what that means for
5 offshore production.
6 MR. POOLE: Well if you go back to the
7 slide where the resources are. I think, you know,
8 I would start with a response that if the
9 moratoria is lifted then potentially the processes
10 that are in place now, in particular with the
11 Minerals Management Service, and if it stays
12 lifted. It is obviously lifted. Would allow more
13 opportunities for exploration of these reserves
14 offshore.
15 There's a couple of items in the plan
16 now. So if they were to move forward, the
17 moratoria would stay lifted, then there would be
18 the opportunity for companies to bid on those
19 leases and move forward with trying to extract
20 those resources. Did that?
21 ADVISOR BROWN: Yes, I think that's
22 good. Obviously this is still in play with the
23 workshop tomorrow in San Francisco and the policy
24 of the new administration could well change; isn't
25 that true?

1 MR. POOLE: Well yes. And my
2 understanding is this is a proposal. And part of
3 the reason for the workshops and the input which
4 you can give up until September is for the
5 Department of the Interior to decide what that,
6 what that leasing plan ultimately will look like.
7 It has a completely new component in it this year
8 in terms of alternatively energy, in terms of wave
9 and wind in particular in the offshore
10 environment. So there's a whole other dimension
11 to it. But until the, until the comments or in
12 then it may or may not remain in the plan.
13 ADVISOR BROWN: Thank you.
14 MR. POOLE: You're welcome.
15 PRESIDING MEMBER BYRON: Thank you for
16 being here. The directional drilling that you
17 talked about that could be implemented on existing
18 platforms. Is that underway yet at all at this
19 point? How much additional opportunity would that
20 present?
21 MR. POOLE: Yes, it is being used in
22 most or all of the platforms, I would assume. I
23 know that in particular it has allowed a couple of
24 operators to get at resources closer to shore from
25 platforms that are further out in the channel in

1 particular.

2 Directional drilling is contemplated in

3 the two projects that are provided for in the

4 provisions of the California moratoria. That's

5 how those resources would be accessed. There's

6 another project currently moving forward in

7 Carpinteria, California, where there would be

8 directional drilling from shore out into a

9 reserve.

10 So I think it clearly is central to the

11 issue. Both currently it is being used across the

12 board with extraction and it would play very

13 significantly in the future. Did that answer your

14 question?

15 PRESIDING MEMBER BYRON: Yes, thank you.

16 MR. POOLE: Okay.

17 ADVISOR BROWN: Could I ask one other

18 question? What ever happened to the Point

19 Arguello field off the coast of Santa Barbara that

20 Chevron was once planning to access. Can you just

21 update us on that.

22 MR. POOLE: My understanding, it is

23 still being produced currently by another company;

24 there are three platforms off the coast that are

25 doing that. However I think that the resources in

1 that particular field if I recall, and I'm trying
2 to recall this from memory, they weren't as large
3 as what Chevron had thought at the time.
4 ADVISOR BROWN: Right.
5 MR. POOLE: And that that onshore --
6 ADVISOR BROWN: And the quality was
7 poor.
8 MR. POOLE: What's that?
9 ADVISOR BROWN: The crude quality was
10 poor too, as I recall.
11 MR. POOLE: Right. Thank you very much.
12 PRESIDING MEMBER BYRON: Thank you.
13 VICE CHAIRMAN BOYD: Thank you.
14 MR. SCHREMP: I have a couple of quick
15 questions for Bob. To expand on what Commissioner
16 Byron started asking about. What resource may be
17 potentially available. Of the 10.5 billion
18 barrels is really any of that resource available
19 through directional drilling from either onshore
20 or any of the existing platforms in state or
21 federal waters?
22 MR. POOLE: In the short answer, yes. I
23 think in terms of a function of the ability of
24 directional drilling to go out seven to eight
25 miles first off. And that there are platforms

1 existing clearly out 12 miles. So from that range
2 you can see that they have a range roughly of
3 about 20 miles. As far as lease-specific. We
4 could go back to the slide that shows the fields
5 and kind of get a little better sense of that.
6 But I think the short answer is clearly yes.
7 Is that it? Okay. Is that it?
8 MR. SCHREMP: Thank you.
9 MR. POOLE: You're welcome.
10 MR. SCHREMP: And Susan, I think there
11 has been some estimates by I think the Energy
12 Information Administration on how much additional
13 resource and when could become available if the
14 moratoria was lifted in all federal waters in the
15 United States. So we can also provide some of
16 that information as part of this process for you.
17 ADVISOR BROWN: And I also assume that
18 we will be closely following the MMS process for
19 opening up those leases and whatever developments
20 occur.
21 MR. SCHREMP: That's correct.
22 Thank you, Bob.
23 And Evelyn Kahl is next.
24 MS. KAHL: Good morning, Commissioners
25 and advisors. I'm Evelyn Kahl and I'm from

1 Alcantar & Kahl, here on behalf of WSPA today.
2 And I have been asked to address two relatively
3 unrelated issues that affect oil production and
4 oil refining in California.
5 And the first one is combined heat and
6 power. And it's a delight to be here and talk
7 about combined heat and power in the context of
8 industry infrastructure rather than simply the
9 electricity sector.
10 And the second issue I'll talk about is
11 a few pipeline access barriers in Southern
12 California to associated gas. And as you know,
13 associated gas can't be produced and restricted,
14 crude oil is restricted.
15 I think we all know in this room that
16 CHP has been identified by the ARB as a key
17 measure in meeting AB 32 goals within the
18 electricity sector.
19 And today we have CHP operating in the
20 state that has been operating for a couple of
21 decades. And it is estimated that that CHP saves
22 between 8 and 20 million metric tons annual. and
23 ARB is looking to increase those savings by an
24 additional 6.7 million metric tons a year. So
25 it's a key element of the scoping plan for

electricity.

And what we are here to talk too about today is continuing to support policies. And I say continue because you have been the greatest champions of CHP policy in the state. To retain existing facilities, promote new development, and to make sure that our RPS policies don't get in the way of CHP.

CHP is an important element of the oil and gas infrastructure. If you look at this graph which is part of the 2005 CEC database it shows that of all of the CHP facilities in California, 45 percent of them are related to oil and gas operations, 13 percent for refining and 32 percent for EOR. So obviously it is very important to the industry and the industry is very important to the state's goals.

With respect to current facilities I'll talk a little bit about what WSPA, the WSPA companies have currently and are contemplating. Today WSPA companies have roughly 2600 to 2700 megawatts of CHP capacity in place. A large majority of it was put in place as a response to PURPA in the late '80s and the early '90s. There were a couple put in place in response to the

energy crisis in the 2002-2003 time frame.

Of all of those facilities roughly half of the electricity in aggregate is exported and the rest remains onsite.

There is additional industry potential. And I know that you will be getting into this in June when you are looking at the CHP potential in California. But within WSPA alone there are about 2,000 megawatts of thermally matched CHP potential and about 200 megawatts of electrically matched.

And there are about, that I can think of offhand there are three refinery projects that are currently on hold for CHP that are either under permitting or have interconnection requests in.

And there are two in the oil producing fields right now that are interesting. And I say interesting because in one case CHP has been foregone already for new boilers, and you may be aware of that. And in another case there was a very large CHP project under consideration in an EOR field that has now been shelved and it is no longer in among the choices being examined being examined by that company to meet their increasing thermal demand.

So those are opportunities arguably

1 lost. The refinery projects are still sitting out
2 there and there are some others to be tapped as
3 well if conditions are right.
4 VICE CHAIRMAN BOYD: Will be addressing
5 that in more detail at our June hearing on the
6 subject?
7 MS. KAHL: Yes, I hope to.
8 VICE CHAIRMAN BOYD: I'd like to hear
9 more about it but not necessarily today.
10 MS. KAHL: And as you know the EOR and
11 refinery CHP are among the most efficient in the
12 state. They are, you know, anywhere from 60 to 80
13 percent on a higher heating value basis.
14 While California has been successful in
15 the past in attracting CHP what this graph shows
16 is that our policy has flatlined. If you look at
17 the dark purple or red line on the graph that
18 shows CHP installation by year. It is not
19 cumulative, it is installations by year. And
20 above that in the dotted line is capacity
21 additions generally in California by year.
22 And what you can see in the middle there
23 is the big PURPA response. And after that you can
24 see a little bit more development. And around
25 1996 we start to go flat. And there was a reason

1 for that. But the fact remains that we have no
2 policy to support new CHP. There is very little
3 that is being developed today.
4 There are a variety of barriers that are
5 leading to this consequence. I think there are
6 certainly limited sales opportunities for excess
7 power coming from these facilities. PURPA was
8 essentially eviscerated by EPAct of 2005 by the
9 feds. The CHP pricing under PURPA that the PUC
10 has implemented just isn't good for bringing new
11 megawatts, it just won't cover the cost of
12 development. And there are no real market
13 alternatives today.
14 Unknown GHG costs and no recovery
15 assurance. So that's got to be factored into the
16 economics and it's really an uncertainty.
17 Utility exit fees are added to the
18 customer capital costs. Right now those range
19 from anywhere from $11 to $29 a megawatt hour,
20 which burdens your project from the outset, as you
21 can well imagine.
22 Complex grid interconnection rules and
23 AQMD restrictions.
24 And finally the last one, which I don't
25 think you can see up here, it's the utility

1 reluctance to take baseload power.
2 I wanted to talk very briefly about it
3 because it is coming up in the RPS context over at
4 the Legislature.
5 The issue is whether the utilities can
6 take any more 24/7 power. And as you know a
7 refinery or an oil producing field needs to
8 operate its CHP around the clock in order to meet
9 the thermal demand. And what the utilities have
10 been saying is we don't need your power because
11 during minimum load conditions we have excess
12 generation. So they are not interested in any
13 more 24/7 power and they are looking for
14 dispatchable power.
15 And this kind of highlights the problem
16 here. If you look at the bar graph on the left it
17 shows the 2010 conditions that have been mapped by
18 the ISO in their average conditions. And in the
19 stack you see all of the must-take resources that
20 are operating during minimum load conditions.
21 And what you can generally see under a
22 20 RPS in 2010 is it's fairly well-balanced. Not
23 during every hour but on average it is fairly
24 well-balanced.
25 If you push it to 33 percent RPS, the

1 bar on the right. You can see the red line across
2 the top there is the minimum load and the stack is
3 the must-take generation during minimum load
4 hours.
5 So you can see if things proceed as the
6 ISO has predicted here we won't have room during
7 minimum load hours for all the resources we are
8 looking for. I don't have an answer for that but
9 it is certainly an issue that needs to be
10 addressed, both as we talk about new RPS resources
11 and as we talk about CHP. What can we do with the
12 minimum load stack until we get to a place where
13 we have real storage opportunities.
14 I won't go through the next three slides
15 with you. They are really just a reiteration of
16 all the agency support that has been voiced for
17 CHP over the last few years. And I have to say,
18 while there have been a lot of kind words there
19 still hasn't been any action. This has been going
20 on for a decade. We can't get traction to really
21 get a CHP policy in place.
22 VICE CHAIRMAN BOYD: We've noticed.
23 MS. KAHL: Yes. And that isn't your
24 doing, I realize.
25 But what we are carrying around I guess,

1 both to ARB, to the CPUC and obviously here is
2 that we need to make efforts to retain our
3 existing generation.
4 Stop trying to unwind prices
5 retroactively.
6 Protect against the EPAct 2005
7 termination.
8 And to get a commercially viable
9 contract in place.
10 In addition we are hoping for a new
11 California-based CHP policy. Something that is
12 like a supply-side energy efficiency portfolio, a
13 feed-in tariff or a PURPA-like program.
14 Let's talk about some prices that will
15 really support these projects.
16 And let's minimize exit fees.
17 And as I mentioned earlier, we need to
18 coordinate our RPS and CHP policies.
19 Moving on to the natural gas pipeline
20 issue. This issue arises because as I said
21 earlier, if you can't get natural gas to market
22 and it's associated gas that means you are leaving
23 oil production behind as well. And there are two
24 very limited issues that have come up in the
25 natural gas context in Southern California that I

1 wanted to share with you. They are both quality
2 related.
3 There was been a long disagreement in
4 Southern California over how quality issues should
5 be handled for California-produced gas.
6 And after years of debate, very many
7 years, we have still be unable to resolve them.
8 One of them is how you really measure the gas
9 quality, over what time period. And the other is
10 how we deal with the ARB NGV standard.
11 And the lack of resolution of these
12 creates uncertainty, it increases flaring in some
13 cases and it results in lower production levels.
14 With respect to sampling and measuring
15 gas quality. Historically SoCalGas used monthly
16 composite sampling. That meant that they had a
17 device that grabbed a sample every so often. At
18 the end of the month they would see what the gas
19 quality was from a particular point of
20 interconnection.
21 And in recent years SoCalGas installed
22 gas chromatographs at most of the points so they
23 are able to measure it instantaneously.
24 And they have been driving the GCs as
25 fast as they will go, which is, you know, they

1 measure in four-minute intervals. And if you have
2 two four-minute intervals that are out of
3 compliance you're shut-in. So there's an alarm
4 that goes off --
5 PRESIDING MEMBER BYRON: GCs are general
6 conditions?
7 MS. KAHL: Gas chromatographs.
8 PRESIDING MEMBER BYRON: Gas
9 chromatographs, thank you.
10 MS. KAHL: And there is no materiality
11 standard here. If your carbon dioxide limit is
12 three percent and you are at 3.1 percent for eight
13 minutes you are shut-in. So it's created a
14 problem in managing the fields in a variety of
15 ways.
16 And one of the ways that the companies
17 have dealt with it is by increasing flaring.
18 Rather than letting that gas go through the
19 pipeline and get shut-in they will flare some of
20 the gas off before it goes into the pipeline and
21 out to SoCalGas to prevent that from happening.
22 So you have increased flaring, and in
23 some cases reduced production, just to avoid the
24 shut-in. Because once you are shut-in it is
25 expensive and it is time-consuming to get back on-

1 line. It's not like you just flip a switch on and
2 off and bring your production back on-line. So we
3 have been discussing this issue with SoCalGas and
4 the PUC for several years and it continues.
5 The last issue is the CARB NGV standard.
6 And this has been going on for years and years as
7 well. And the question is, how do we apply ARB's
8 NGV standard, their CARB 6 standard or their
9 methane number, with respect to pipeline access.
10 And the PUC has said twice that the ARB standards
11 are not pipeline standards. And yet still
12 SoCalGas uses them as pipeline standards to
13 prohibit access of some supplies to their system
14 over certain pipelines.
15 The position they have taken is, well
16 they don't apply the full CARB 6 standard or the
17 methane number standard. What they are saying is,
18 we are going to grab the six percent ethane limit
19 out of that standard and apply it to the gas
20 coming in from California producers.
21 Again it is limited flexibility for
22 California production coming to market.
23 So those are all my comments and I'm
24 happy to answer any questions you have.
25 VICE CHAIRMAN BOYD: I anticipate we'll

1 see you back here, Evelyn, for at least two
2 different hearings, the natural gas hearing and
3 the CHP hearing of the IEPR Committee.
4 PRESIDING MEMBER BYRON: Ms. Kahl, you
5 went through a lot of material very quickly. I'd
6 like to think I know a little bit about the CHP
7 but I had difficulty even keeping up with you.
8 Could you go back to Slide 9 please and take a
9 little bit more time and explain what this slide
10 is about.
11 MS. KAHL: Okay. This slide is about
12 how the state's electricity supply looks during
13 minimum load hours. And minimum load hours are
14 the hours when the state's demand is lowest. And
15 typically they occur at night, off-peak hours. So
16 the demand is very low.
17 Yet when the demand is very low you have
18 a certain number of resources that need to be
19 operating, as you know. Your hydro in some cases,
20 nukes. Some minimum --
21 PRESIDING MEMBER BYRON: So when you say
22 must-takes you are also including in all the
23 renewables here too.
24 MS. KAHL: Right, right. And
25 renewables, it's primarily wind and geothermal I

1 think at this point because solar isn't on during
2 the off-peak hours.
3 PRESIDING MEMBER BYRON: It doesn't
4 operate at night yet.
5 MS. KAHL: So you have got a situation
6 where your minimum load may not match your must-
7 take resources or your minimum generation during
8 those hours. And the question is on the stack on
9 the right, if you get to a point where your
10 resources that must run during the hours are in
11 excess of your load, what do you do and what's the
12 value of those resources at that point.
13 And so the point is that the utilities
14 are using this argument to say, we don't want any
15 more CHP because it's 24/7 in many cases. We just
16 don't need 24/7 anymore.
17 PRESIDING MEMBER BYRON: Right. Of
18 course Commissioner Boyd and I still continue to
19 sit on a lot of siting cases where we are
20 continuing to site a number of baseloaded natural
21 gas-fired power plants.
22 MS. KAHL: Yes.
23 PRESIDING MEMBER BYRON: All right,
24 thank you for taking that time.
25 Moving on just a little bit. With

1 regard to promoting new CHP generation. We did
2 have a workshop on -- today is Wednesday.
3 MS. KAHL: Monday.
4 PRESIDING MEMBER BYRON: Monday. Were
5 you here for that as well?
6 MS. KAHL: Yes I was.
7 PRESIDING MEMBER BYRON: And we learned
8 a great there with regard to the AB 1613
9 legislation that is underway. As I recall,
10 though, the large producers are not going to
11 participate in 1613. Primarily for what reason?
12 Is it resources? Is it too small of a megawatt
13 threshold?
14 MS. KAHL: It is, it's a 20 megawatt and
15 under proceeding. And as you probably know, at
16 the oil refining and production facilities they
17 are much larger facilities typically starting at
18 40, 42 megawatts. So it's not relevant for these
19 companies. And what we are hoping is that the PUC
20 follows through with its promise to have a
21 rulemaking on the larger CHP facilities this
22 summer.
23 PRESIDING MEMBER BYRON: All right. And
24 of course what we are trying to do is, I believe
25 Assembly Member Blakeslee's legislation was trying

1 to get a foothold, if you will, and so we are
2 starting with 20 megawatts and below. Which is
3 still substantial in size. But you are absolutely
4 right, not big enough for the cogeneration
5 opportunities at refineries. Okay. Well, this is
6 very good. And I do hope we will continue to hear
7 from you.
8 Commissioner, it just seems to me though
9 that based upon what I have heard from this
10 presentation, Southern California Gas and Southern
11 California Edison just don't seem to like these
12 folks. That's the impression I get. I mean, this
13 has been going on for a long time.
14 MS. KAHL: Years and years.
15 VICE CHAIRMAN BOYD: Decades.
16 MS. KAHL: Yes, it is actually decades
17 in some cases.
18 You know, and in closing too I would
19 like to ask your help with one issue. Which is,
20 you clearly understand the issue, you understand
21 its importance. But we can't seem to communicate
22 with ARB and the PUC about it. At times it's the
23 timing question.
24 As I explained, we have a couple of
25 projects that could have been built that probably

1 won't be built. And this is all about timing.
2 And, you know, starting in the summer is terrific
3 but we'll be done five years from now and all
4 those opportunities will have passed us by with
5 boilers.
6 So thank you.
7 PRESIDING MEMBER BYRON: Thank you.
8 MR. SCHREMP: Thank you, Evelyn.
9 We have Rock Zierman from California
10 Independent Producers (sic) Association. And then
11 on deck would be Dominic Ferrari.
12 MR. ZIERMAN: Good morning,
13 Commissioners, advisors. Thanks for the
14 opportunity to be with you today. Rock Zierman,
15 California Independent Petroleum Association.
16 In an effort not to be repetitive I
17 wanted to focus on specifically two questions that
18 Gordon and staff raised in their document.
19 Specifically, can you stem the decline in
20 production in California? And number two, are
21 there regulations, such as AB 32, if you are
22 successful in doing that that would threaten that?
23 And the spoiler alert is the answer to
24 both of those is yes. In fact, that's not really
25 conjecture but what we have seen in production

1 numbers last year. In 2007 onshore production in
2 California was 203 million barrels of crude. In
3 2008 it was 203 million barrels of crude because
4 of the heavy drilling activity. Where we got the
5 decline was actually offshore. So if you open up
6 offshore access you can actually and very credibly
7 stem that tide.
8 So I wanted to focus on is what sort of
9 scenarios do you have to have in order to have
10 that take place.
11 When companies are making decisions
12 about when and where to invest I wanted to focus
13 on some of the questions that run through their
14 mind. Number one, this is a very expensive, very
15 capital-intensive industry and you have to have
16 access to that capital in order to drill.
17 Secondly, obviously you need a rig, a
18 drilling rig in order to do that. Typically
19 companies don't own their own rigs, they contract
20 with drilling companies specifically. Offshore
21 production and offshore platforms are the
22 exception, typically. They have their own rigs
23 that are permanently placed on there. We'll talk
24 about that a little bit.
25 Once you have capital and a rig you also

1 have to get permission from local, state and
2 federal agencies in order to drill. So we'll look
3 at some of the biological hurdles and the
4 biological calendar that you have to follow in
5 order to complete your drill.
6 And when you're talking about minerals
7 obviously that are on state and federal lands you
8 have to have permission from those agencies to
9 access those minerals.
10 And there are also subsets. These first
11 four issues are global and universal and every
12 company in every state and every country faced
13 these four things. But there are individual
14 dynamics in each market that are particular to
15 that market that affect whether or not somebody
16 drills there and we'll look at some of those as
17 well. Obviously one of those on the horizon in
18 California is AB 32.
19 Just quickly on the capital issue.
20 Obviously it's capital-intensive. Independents
21 are actually heavily engaged in drilling. They
22 are almost exclusively doing the exploratory wells
23 nationally. A study has shown that they reinvest
24 up to 150 percent of their net revenues into new
25 drilling.

1 Well how do they do that? Well they
2 have to go out, obviously, and get equity partners
3 or bank loans to provide that extra 50 percent in
4 order to drill. They are constantly looking at
5 the future and how they can continue to operate
6 since they have obviously a resource that
7 naturally declines.
8 So the credit crunch that has faced the
9 entire country has obviously affected our industry
10 as well. It is much more difficult to go out
11 there and get that credit in general. It is more
12 difficult to go get it specifically when the price
13 of crude has fallen so dramatically.
14 And lastly, the President has proposed a
15 budget that has a $31.5 billion increase in taxes
16 on our industry, primarily from the tax treatments
17 we get for drilling new wells. Tangible drilling
18 costs, percentage of depletion, geophysical and
19 geological deductions that we currently get, the
20 President has proposed to eliminate those. Those
21 are treatments that we have had since 1913 in
22 recognition that they want to encourage this risky
23 business because it is in the nation's best
24 interest in order to have that infrastructure and
25 meet our energy needs.

1 On drilling rig availability, just some
2 numbers to put it in perspective. In July of last
3 year nationally there were 2400 active drilling
4 rigs in the country and six months later that was
5 cut in half, 1200 rigs.
6 It basically took us the better part of
7 four or five years to get to that 2400 number and
8 it only took six months to basically mothball that
9 capital and layoff that personnel. And when we go
10 to, if the demand in fact turns around it is going
11 to take some time to revamp up.
12 Historically to give you a perspective,
13 1981 was the peak, 4,500 active rigs in the
14 nation. Six years later just 663. So a very
15 cyclical industry that we're facing. And given
16 that we don't own the drilling rigs we do depend
17 on those companies in order to have access to
18 those drilling rigs when, in fact, we want to go
19 out and get the new resources.
20 The cost tends to be a lagging
21 indicator. It tends to -- as the price increases
22 it lags before the price increases and when the
23 price drops, the price of crude, the price and
24 expense of drilling tends to lag. It's now begun
25 to come down because we have had those costs

1 decrease and because the demand on the rigs are
2 lower.
3 This is going to have, as we are looking
4 into future. If and when we are successful in
5 getting the economy back we are also probably
6 going to look at energy demand globally coming
7 back very strong. Prices rising and the demand
8 for drilling rigs increasing.
9 You will see that, as I mentioned, it
10 doesn't take much time to mothball that capital
11 and that personnel. It does take a long time to
12 revamp up. And so that's something that we are
13 going to have to look at.
14 And I mentioned the effect it's had on
15 production. They predict that in 2009 domestic
16 production will actually increase from the year
17 prior for the first time in a long time because of
18 all the activity. And so that gets to the
19 question that yes, it is possible to stem the
20 decline curve.
21 Obviously you have to have permission
22 from the various local, state and federal
23 agencies. We deal with the Endangered Species Act
24 which requires consultation with Fish and Game,
25 Fish and Wildlife, local agencies and the like.

1 And that has to not only mesh with getting
2 permission but within those permits there are
3 specific biological calendars. There's mating
4 seasons. Particular endangered species which you
5 are not allowed to drill.
6 So when you combine the drilling rig
7 availability, which at the peak it was six months
8 to a year that you had to wait for a drilling rig.
9 And then you have this biological calendar and you
10 have to go get permission through these
11 consultations, you can see how difficult in some
12 parts it is to make that all match up. That you
13 request six months to a year a drilling rig, not
14 yet having permission from the agency to go drill
15 and hoping that you make that biological calendar.
16 So that's a difficult hurdle that we face as well.
17 Often when we are in sensitive lands we
18 have to offset those lands for species and you can
19 do that through Habitat Conservation Plans.
20 However those are very difficult to get approved.
21 Kern County has been working on a HCP for 15 years
22 and have not been successful at getting it. But
23 we continue to work at it and we are hopeful that
24 they do. So companies are having to go to other
25 land banks or do their own HCP in order to get

1 offset lands in order to continue to drill in
2 those areas.
3 Obviously air rules are a big concern
4 and something that we look at. We have very
5 stringent air rules which we have been complying
6 with for 15 years successfully but there are some
7 issues there on the horizon. As you might have
8 heard in the South Coast there was a lawsuit on
9 the air credits that have prevented those air
10 credits from being used because the air district
11 was sued by environmental groups and NGOs. And so
12 those credits are no longer available for new
13 production. So issues like that are very much at
14 the forefront in our ability to drill more in the
15 future.
16 There are also water rules. This is
17 very intensive. In some areas basically we have
18 water companies that make a little bit of oil.
19 THUMBS and Tidelands down in Long Beach actually
20 have a 95 percent water cut. So they are taking
21 out, what is coming out of the well is about 95 to
22 97 percent water and just a small sheen of oil.
23 So then it's very intensive, energy intensive to
24 do that and to reinject that water and all the
25 rules that go with it.

1 Bob Poole mentioned offshore the state
2 and federal moratorium. But I did want to just
3 expand on that a little bit. One of the things he
4 mentioned was that MMS estimates that there's ten
5 billion barrels in federal lands in the OCS off
6 the Pacific coast. As a point of reference,
7 that's a 1985 number. Obviously there hasn't been
8 a lot of seismic activity done in the last 25
9 years because of the moratorium.
10 And as a point of reference, the MMS at
11 that same year predicted that in the Gulf Coast
12 there were nine billion barrels of oil available
13 in the OCS. Twenty-five years later after 6,000
14 platforms were installed in the Gulf, 4,000 of
15 which continue to operate today -- we have just 27
16 but they have 4,000 that are operating today.
17 Twenty-five years later we now predict that
18 there's 45 billion barrels of crude in reserve.
19 So that gives you a sense that they were off by a
20 factor of five and so these may be very
21 conservative numbers when it comes to the ten
22 billion that's available off the California coast.
23 So I just wanted to mention that.
24 Also I wanted to mention, Bob mentioned
25 the specific proposal that went before the State

1 Lands Commission by Plains Exploration, the
2 Tranquillon Ridge Project. In some of the
3 documents that were part of that process it
4 predicted that at the peak, which it would take
5 about two years to drill and reach the peak of
6 production, you may see 30,000 barrels a day in
7 production from that one project.
8 So to put that in perspective. If we
9 are making 650,000 barrels a day and you have got
10 30,000 increased barrels from one project, you
11 know you are looking at somewhere between 18 and
12 20 percent -- I'm sorry, somewhere around 5
13 percent increase in just one project. And so that
14 could overcome some of the depletion and other
15 parts of offshore.
16 And that's just one project. Obviously
17 Veneco's project in Carpinteria and other
18 prospects that there are with the directional
19 drilling, you can see that we legitimately can
20 answer that first question, yes, we can slow the
21 decline curve if we have access to those
22 resources.
23 We have been engaged at the federal
24 level on the federal moratorium. There have been
25 different proposals about bringing the moratorium

1 back in a more limited scope. The Speaker of the
2 House said that she recommended maybe the first 50
3 miles the state can buy in and from 50 miles to
4 100 miles there would be no moratorium.
5 Well none of these ten billion, or
6 virtually none of these ten billion barrels of oil
7 exist beyond 100 miles. I don't know of any
8 company that is interested in going out 100 miles
9 off the Pacific Coast in those waters installing
10 platforms and so that is in fact a moratorium.
11 What we have suggested is that if a
12 limited moratorium has to come back let's look at
13 utilizing our existing infrastructure, our 27
14 offshore platforms as well as onshore locations,
15 which we can use directional drilling to reach
16 those. And we can reach a tremendous amount of
17 those 36 disputed leases as well as other
18 resources that may be out there on the offshore if
19 we had a moratorium that limited it to existing
20 infrastructure or onshore locations.
21 And just quickly on the individual
22 market dynamics. One thing is you always hear
23 about WTI, West Texas intermediate price. That's
24 the price we hear on the television every night
25 what it is. But there is always a differential

1 between California crude and WTI price. And that
2 is not always based on gravity. It is based --
3 because our light crude also has a differential.
4 But you can see that it has changed
5 quite a bit recently. Typically over the last
6 three to four years it has ranged from $10 to $15.
7 In July of last year it was $14 when WTI was $147.
8 But in February despite WTI going down more than
9 $100 a barrel the differential was still $10. And
10 so these are the individual dynamics that
11 companies can consider on whether to invest
12 specifically in California.
13 What causes that? There's a whole host
14 of things that cause it. We talked about the ANS,
15 which had an export ban when it was first
16 produced. So much of that crude, 1.5 barrels were
17 dumped on the California market and that
18 suppressed the price for heavy crude.
19 ANWR is unlikely to be opened up in this
20 Congress with this president. However, all the
21 bills that are introduced do have provisions in
22 them for this export ban. And this is an actual
23 molecule export ban that this barrel of crude that
24 is produced cannot go to, cannot travel anywhere
25 outside the United States. We suggested that you

1 can have an export ban by being able to trade so
2 that you don't have these market mechanisms that
3 suppress the price here in California and in turn
4 reduce the drilling operations in California.
5 We talked a little bit about Big West
6 and Flying J. The bankrupt refinery down there
7 that is no longer purchasing crude. They
8 purchased tens of thousands of barrels a day from
9 folks in Kern County. That went away and so folks
10 had to scramble to deliver that crude somewhere
11 else. There is also an application for a San
12 Joaquin pipeline that feeds crude to Martinez to
13 be shut down for heavy crude which needs to be
14 heat-treated. So those are specific issues for
15 Kern County about whether or not you strand those
16 assets in Kern County.
17 And then obviously if you had a
18 California severance tax of 9.9 percent, which
19 they contemplated, that would further drive down
20 the attractiveness of coming into California to
21 invest.
22 AB 32, quickly. Right now we are
23 operating under uncertainty. There is no
24 statewide program. There is no recognized
25 thresholds of significance. When people are doing

1 EIRs there are no recognized mitigation measures.
2 And so there's a lot of uncertainty on how to
3 comply today. Obviously CARB is in the process of
4 developing a Scoping Plan and possibly a cap and
5 trade market to take care of that. But today we
6 operate under uncertainty. And where there's
7 uncertainty and where there's a vacuum folks move
8 in to fuel that vacuum.
9 In California it's largely been the
10 attorney general who has come in and sued certain
11 local agencies that are considering projects,
12 particularly projects that we are talking about
13 today, and forced his own opinion as far as what
14 the significance levels are, what the mitigation
15 levels should be. And obviously we would all
16 benefit if there was a program that is agreed
17 upon, that we all live under the same rules.
18 Cap and trade is something that we
19 support, provided that the credits that you can
20 operate with are allocated and not auctioned off.
21 We should do this in the most cost-effective way
22 and auctions are a way to raise a great deal of
23 money. However, it is also a way to raise the
24 cost of complying with AB 32.
25 We are looking at will the federal

1 government come in and supersede the state.
2 Obviously when you have a cap and trade program
3 for something that is global in nature the larger
4 the market the better. And so we support a
5 federal program superseding any state program,
6 because the larger the better.
7 I think the Low-Carbon Fuel Standard
8 largely will not affect production in California.
9 Because CARB I think wisely has chosen to give one
10 carbon score to all feedstock, all crude
11 feedstock. So I think we are going to be okay
12 complying with the LCFS.
13 And there's also opportunities. CO2
14 capture and storage has been talked about. It's a
15 big opportunity not only to enhance oil recovery
16 but also a mechanism that others can use in order
17 to store CO2 that's produced by other industrial
18 uses and help us comply with AB 32.
19 And with that I will be happy to take
20 any questions you have.
21 PRESIDING MEMBER BYRON: Very good.
22 ADVISOR BROWN: Could I ask one
23 question, Rock?
24 MR. ZIERMAN: Yes.
25 ADVISOR BROWN: How does the Low-Carbon

1 Fuel Standard treat oil sands?
2 MR. ZIERMAN: I believe that there is
3 going to be -- the one carbon score is going to be
4 for traditional feedstocks, which that obviously
5 would not be. And so what they propose is to have
6 a separate score perhaps for non-traditional
7 feedstock. But give them an opportunity to do
8 studies, to demonstrate that their actual carbon
9 score may be lower than that one, than that one,
10 thank that CARB sore that they give them. So
11 that's my understanding of where the discussion is
12 today.
13 ADVISOR BROWN: So it is conceivable
14 they will use some kind of life cycle cost
15 analysis to --
16 MR. ZIERMAN: Correct.
17 ADVISOR BROWN: -- arrive at the right
18 score for conventional versus unconventional.
19 MR. ZIERMAN: Right. As a lot of
20 Canadian companies have been participating in this
21 process they have been mentioning programs that
22 they are implementing similar to AB 32 in order to
23 reduce their carbon footprint and get closer to
24 the same carbon footprint as California
25 production.

1 VICE CHAIRMAN BOYD: Thank you.
2 PRESIDING MEMBER BYRON: Thank you,
3 Mr. Zierman.
4 MR. SCHREMP: And just for
5 clarification, Rock. You said the Air Board has
6 one carbon score for traditional. Does the Air
7 Board consider enhanced oil recovery using a lot
8 of steam injection as traditional?
9 MR. ZIERMAN: Yes, my understanding is
10 yes. Anything that is part of the feedstock today
11 in California, which certainly EOR oil is, would
12 be given that one carbon score.
13 MR. SCHREMP: And then if you could just
14 quickly. Was there a main reason or reasons why
15 the request for Tranquillon Ridge as rejected or
16 denied?
17 MR. ZIERMAN: Well obviously I don't sit
18 on that panel and don't have, can't get in the
19 brain of those folks that are in there. But
20 obviously we are disappointed given the support
21 amongst environmental groups and all the benefits
22 that went with it. I think at the end of the day
23 offshore production is a very, a very scary issue
24 for a lot of decision makers and they don't want
25 to get tied into being perceived as pro-offshore oil.

However, we have done numerous surveys. And when it comes to opposition to offshore we think that the main thing the public objects to is the installation of new offshore platforms. And obviously this is a project that would not do that. It would utilize existing infrastructure. And in fact, as I mentioned, we can get most of those resources from existing infrastructure. So I think at the end of the day probably some people had a negative reaction to the overall issue given their political futures.

MR. SCHREMP: Thank you very much, Rock.

We have Dominic Ferrari from Plains All American.

MR. FERRARI: Good morning, Commissioners, members of the audience. My name is Dominic Ferrari, vice president of Plains All American Pipeline. I am in charge of all of our operations on the West Coast and predominately California. I am here today to speak on behalf of Plains on the Pier 400 Project.

A little background, quick background on our company. As you may or may not know we are headquartered in Houston, Texas but we do have a significant presence here in California. We have

1 a major office in Long Beach, Bakersfield, where
2 we manage most of our assets.
3 As a lot of the speakers mentioned this
4 morning there is a serious lack of infrastructure
5 in California, especially in Southern California.
6 So I am not going to dwell on that, I am really
7 here to give you an update status on our project.
8 Again a lot of these discussion points
9 you have already heard about domestic crude
10 declining and a lot of the assumptions. Several
11 speakers have hit on this so again I am not going
12 to go over it. Our project, though, is an import
13 facility and you will see hopefully it will be a
14 solution.
15 A little bit about the project. And
16 I've got some maps coming up to show you. We call
17 it Berth 408. It's in the Port of Los Angeles.
18 Number one, it's got 81 feet of water.
19 Basically it will be able to handle any vessel
20 from anywhere in the world. This is very
21 significant because, as you heard, we are
22 expecting, unfortunately, Middle East crude to
23 keep coming. And it comes in VLCCs and those guys
24 need deep water. If you don't have deep water
25 they have to lighter and do other things and it

1 just drives up the cost. So this is a key point
2 of this infrastructure project.
3 The capacity is significant. We are
4 designing it for an initial capacity of 350,000
5 barrels per day so this is a major facility.
6 And of course we always build in
7 provisions to expand over time if the market
8 dictates.
9 The project also includes a significant
10 amount of storage. When you build a project like
11 this you need a lot of storage tankage to handle
12 the crude oil so we are planning initially on four
13 million barrels of storage tanks.
14 The offloading rates are up to 100,000
15 barrels per hour, which again is world class. The
16 100,000 barrel per hour offloading rate. There's
17 probably one other terminal in the United States
18 that does that off the coast of Louisiana. Again,
19 this is a world class type of facility.
20 Obviously we were designing this to be
21 very environmental, environmentally friendly.
22 And safety and security are absolutely
23 key in a project like this.
24 A little map here to show you, give you
25 an idea of the project. If you look out on the

1 water you can see an arrow pointing at Berth 408
2 and you can see a vessel there. That's where a
3 vessel would come in and offload. There's a 42-
4 inch pipeline that would connect that area and go
5 around the Pier 400 land mass over to where we
6 show the project tankage. And that, again, would
7 have our 4 million barrels.
8 The key to any facility like this is to
9 get the vessel in, offload them real quick and get
10 them out. They are very expensive and they need
11 to, they can't sit there. So this is all designed
12 to get these guys in and out.
13 You can also see the entry where it says
14 Berth 408. That is called Angel's Gate. That's
15 where the vessels come in from the Pacific Ocean.
16 And you can see the access to our dock is very
17 simple. It's all been designed that way. The
18 people, the Port of LA designed this land mass and
19 they did a wonderful job as far as being able to
20 get vessels in quickly, safely and out. It's kind
21 of an overview. And you can see the town of San
22 Pedro right below there, to give you an idea of
23 where this is.
24 This is kind of a busy map but the whole
25 point is that again it's one thing to build a

1 facility like this and build tankage but at the
2 end of the day you've got to get it to the
3 refineries that we discussed this morning.
4 Our company owns and operates a
5 significant pipeline infrastructure in Los Angeles
6 with tankage. We are already connected. We
7 already serve all the refineries with our
8 pipelines from Bakersfield. We operate two major
9 pipelines from Bakersfield to LA and we supply all
10 refineries in Los Angeles. So the good news is
11 here we don't have to duplicate or replicate any
12 more pipelines an tankage in LA. It's all there
13 and it will be hooked up to our Pier 400 project.
14 Okay, let's get to entitlement. This
15 again has been a long road. I think Commissioner
16 Boyd mentioned earlier that this has been going on
17 for awhile and it sure has. But we feel we are
18 getting close.
19 The main steps to get this thing going
20 is to get approval, final approval of our EIR and
21 EIS.
22 We are still working on a Harbor
23 Commission approval for land lease.
24 We need City Hall approval of our Harbor
25 Department permit.

1 And we need an AQMD permit. And I'll
2 talk about these items in a minute.
3 We did have a little delay in our CEQA
4 process here recently.
5 It really caused about a two-year delay.
6 Bottom line is we obviously had to
7 perform an EIR.
8 And that process, even though it was
9 long it actually went pretty well. But we had a
10 protestant right at the end and that caused us a
11 significant amount of time to deal with. The good
12 news is that we have been able to answer all those
13 questions and get our EIR back on track and I'm
14 going to talk a little bit more about that.
15 Capital costs have gone up on the
16 project. Again, it has been going on so long.
17 But it's kind of interesting. Last year as you
18 all know we had steel going through the roof and
19 we couldn't find contractors. Canada was taking
20 all of our contractors. That's all been reversed.
21 Steel is coming back down, contractors are hungry,
22 so we actually have seen a reversal in this trend
23 and pretty, pretty optimistic about our ability to
24 control our capital on this project.
25 This project, again it's a significant

1 project. It would employ a lot of people, a lot
2 of construction people in LA and a lot of
3 permitted operating jobs. So we are anxious to
4 get this going for that reason.
5 This is a timeline that I don't know
6 that I'm really going to bore you with, other than
7 I guess the whole point is that we did apply to
8 the Port of LA in April of 2003. That's when we
9 got this kicked off. And actually we were here to
10 introduce the project to the CEC in 2003. I am
11 not going to go through all of the steps but you
12 can see how long it takes to get this done.
13 The key bullet point here is the current
14 station and construction period.
15 Our draft EIR was approved by the Harbor
16 Commission in November of 2008. It was a
17 unanimous vote by the Port of LA Harbor Commission
18 and we were very, very thrilled about that. But
19 we did get the appeal in December and that was our
20 latest setback. Now again, we've dealt with that.
21 Our EIR and land lease goes to vote
22 today to the City Council. So the LA City Council
23 is voting on our project today. So we have got
24 our fingers crossed. We believe the City is going
25 to support us. Certainly with the Harbor

1 Commission giving us a positive vote we would be
2 very surprised if the City didn't but we have
3 gotten surprised here a couple of times so we are
4 just going to keep our fingers crossed. With an
5 LA City Council approval today we will be in very
6 good shape. There is always an appeal period but
7 I think we will be in good shape after today's
8 vote.
9 As far as moving on here's a couple of
10 more bullet points. But the bottom line, to get
11 to the bottom bullet point. It's going to take a
12 couple of years to build this. Again, it's a
13 major facility. And we are projecting opening up
14 the facility for business in early 2012. So
15 bottom line is we need a couple of years to build
16 this as long as we don't get any more delays.
17 This was a slide on supply and demand.
18 And again I am not going to go through this
19 because there has been excellent presentations on
20 this today. The only thing at the bottom is here
21 we do talk about the other berths in Southern
22 California that are handling oil today.
23 And you can see some of the problems.
24 For instance, 121 in Long Beach. That is a
25 significant facility but it's maxxed out. BP/

1 ConocoPhillips basically dominate that dock and
2 nobody else can get in. Tesoro is a smaller
3 facility, can't really move a lot of oil in there.
4 And ExxonMobil is being take out of service so we
5 have got a real problem there. Chevron has their
6 own facility. Again, they are running a lot of
7 Middle Eastern crude, as was discussed this
8 morning.
9 VICE CHAIRMAN BOYD: The ExxonMobil that
10 you say is out of service. Is that a permanent
11 out of service?
12 MR. FERRARI: Well.
13 VICE CHAIRMAN BOYD: It sounded like it.
14 MR. FERRARI: Commissioner, it's kind of
15 a sensitive subject. But, you know, the whole,
16 the whole principle behind the Pier 400 -- let me
17 see if I can go back real quick. The whole
18 principle behind building Pier 400. You know,
19 it's a manmade island. If you look where it says
20 Maersk and Berth 408, that's 400 acres of land
21 mass that was put in by the Port.
22 They got federal funds basically to move
23 the oil operations away from the inland area. The
24 Exxon terminal and other terminals are located in
25 these inner waterways and they are close to the

1 public. So the whole idea of building Pier 400
2 was to move oil out and get it away from the
3 public. Exxon is on that list.
4 VICE CHAIRMAN BOYD: Okay. I kind of
5 know the history of Pier 400. All those cargo
6 containers weren't assumed to be there in the
7 beginning, if I remember right.
8 MR. FERRARI: That's correct,
9 Commissioner, it was supposed to be an all-oil
10 facility. But because of delays and difficulties
11 and getting things permitted the containers came
12 in. But we still, we still have a spot to build
13 our project.
14 VICE CHAIRMAN BOYD: Thank you.
15 MR. FERRARI: These are just some other
16 comments we had today about other, other
17 facilities. As you all know MOTEMS, the State
18 Lands came out with MOTEMS. And a lot of the
19 facilities are complying with MOTEMS and upgrading
20 their docks. And we see that as definitely a
21 positive and the other operators upgrading their
22 facilities for safety and security reasons. So I
23 think that's a real positive development
24 California State Lands implemented. Obviously our
25 facility is going to be designed according to

1 MOTEMS.

2 On the other hand a lot of the

3 facilities are old. They have wooden piles. They

4 are just, you know, 50 years old or higher. Some

5 of the facilities are going to get upgraded with

6 MOTEMS and some probably will go by the wayside.

7 So we'll just have to see how that goes.

8 That concludes my presentation. It was

9 really, really an update on our project. If you

10 have any questions I'd be happy, happy to answer

11 them.

12 VICE CHAIRMAN BOYD: No more from me.

13 ADVISOR SCHWYZER: I have a question,

14 actually.

15 PRESIDING MEMBER BYRON: Go right ahead.

16 ADVISOR SCHWYZER: I noticed one of the

17 permits you still need is the AQMD permit to

18 construct. Do you anticipate any difficulty with

19 that one?

20 MR. FERRARI: No, not at all. The

21 permit is actually already, already drafted. But

22 the way they work is they wait until the final EIR

23 is approved and everybody is signed off and then

24 they, and then they actually give you the piece of

25 paper. So it's done, we have no more

1 negotiations. But, you know, we don't actually
2 have the paper yet. But we'll get it. Very
3 confident.
4 PRESIDING MEMBER BYRON: Mr. Ferrari,
5 probably I should know this but I'll ask. Which
6 organization had the CEQA responsibility in your
7 permitting? Is there a single agency that it's --
8 VICE CHAIRMAN BOYD: Who is the lead
9 agency?
10 PRESIDING MEMBER BYRON: The lead
11 agency.
12 MR. FERRARI: We had two lead agencies.
13 The Port of Los Angeles was the lead agency for
14 the EIR and the Army Corps of Engineers was the
15 lead agency for the other. So we had two, two
16 lead agencies. And again, the Port of LA is a
17 very, very, very good agency to work with.
18 PRESIDING MEMBER BYRON: Well, and I
19 realize you are up for a vote today so this might
20 not be the right time to ask this question. But
21 you have made a recommendation here that CEQA
22 process be reviewed and modified to minimize the
23 ability for minor issues to be allowed to delay
24 important projects. So if you don't care to
25 answer this question today I'd understand. Maybe

1 though you could let us know in writing in the
2 future what specific recommendations you might
3 have along those lines.
4 MR. FERRARI: We would be very happy to
5 kind of do a look-back on this project with you
6 and put some things down in writing. Because
7 obviously it has taken five or six years, you
8 know, the permit. And we understand it's a major
9 project but there are little things that come up
10 that just, you know, really shouldn't stop a
11 project like this or slow it down. Really not
12 ready to talk about it today but we do, we would
13 like to do a look-back.
14 I will say one thing, if I had a couple
15 of minutes. We came up and presented this project
16 to the Energy Commission when we first started
17 five or six years ago. And at that time we were
18 getting a lot of heat from one agency that I am
19 not going to mention. The Commissioners listened
20 to what we were saying.
21 And basically at that time, I don't know
22 if Commissioner Boyd remembers, but you guys were
23 thinking about streamlining, going to streamlining
24 and basically just taking over the permitting.
25 And after that meeting, I'll tell you, things

1 opened up, things really got easy for us. So we
2 appreciate that one stance that you folks took six
3 years ago. I can't tell you how much that changed
4 people's attitudes.
5 VICE CHAIRMAN BOYD: Yeah, well we got a
6 lot of bruises.
7 MR. FERRARI: Yeah. Do you remember
8 that, Commissioner Boyd?
9 VICE CHAIRMAN BOYD: Yes I do.
10 MR. FERRARI: Well that was very
11 effective, thank you.
12 PRESIDING MEMBER BYRON: All right, well
13 Commissioner Boyd will clue me in later. But we
14 would be interested in your recommendations when
15 you do that look-back. I think that could be very
16 helpful to this Commission.
17 MR. FERRARI: Very good sir. We will
18 provide it, thank you.
19 PRESIDING MEMBER BYRON: Thank you for
20 coming.
21 MR. SCHREMP: Thank you very much,
22 Dominic. The next speaker is Seth Jacobson.
23 MR. JACOBSON: Thank you very much for
24 inviting us to speak today. My name is Seth
25 Jacobson, I'm from CAST. We are a California-

1 based nonprofit organization that was founded in
2 2005 by national security professionals, including
3 Dr. Abraham Wagner who leads the organization. He
4 served under five different presidents at the
5 federal level, including on the National Security
6 Council, and was director of DARPA for awhile.
7 We also co-host an annual conference
8 with RAND down in Santa Monica on terrorism and
9 global security. This analysis was originally
10 developed for our 2008 conference. It's a work in
11 progress. Our goal is to evaluate the growing
12 vulnerability of Los Angeles and California to
13 disruptions in the global supply chain,
14 particularly from terrorism.
15 As a summary, and as had been said
16 before by other speakers today, we Californians
17 are increasingly vulnerable to terrorist attacks
18 on our oil supplies. This is a politics and
19 economics issue.
20 And with that in mind as we look forward
21 to US withdrawal from Iraq we believe that the
22 withdrawal will heighten California's
23 vulnerability and that we Californians should
24 implement policies to develop resilience to
25 disruptions in the supply chain.

1 And one policy recommendation that we
2 are making is the development of a strategic
3 petroleum reserve in the western US to provide
4 surge capacity.
5 This is just a reflection of what's been
6 mentioned earlier and is from the CEC website. We
7 are past peak production, domestic production
8 peaked long ago, and we are increasingly reliant
9 on unreliable foreign sources for our oil
10 consumption.
11 An attack on LA's oil imports is not
12 simply Los Angeles's problem. As has been
13 mentioned the refineries in Southern California
14 serve about 25 million Americans in the
15 southwestern United States. And of course we have
16 imports into the northern refineries in Northern
17 California as well. But obviously disruption will
18 cause major economic damage to the region.
19 This is based on a chart that was
20 presented earlier today from the gentleman from
21 Baker. We down in Southern California, our
22 refineries already use a majority of foreign oil.
23 It was mentioned yesterday that the United States
24 imports about 60 percent of oil consumption.
25 Southern California has about, I think, 56 percent

1 now of our refinery runs are foreign imports.
2 But all foreign imports are not created
3 equal. The source of those imports is really
4 important for us to take a look at.
5 As was also mentioned earlier, I just
6 want to reiterate that in about five years it is
7 projected that no oil will be coming from Alaska
8 to Southern California's refineries. At which
9 point the overwhelming majority of the oil
10 consumption will be foreign imports, primarily
11 from the Middle East.
12 The reason that this is important, of
13 course, as I mentioned earlier, is that all
14 imports are not created equal. Since 2003 with
15 the invasion of Iraq the number one source of
16 foreign imports to Southern California's refinery
17 is Iraqi oil, surpassing Saudi Arabia and Ecuador,
18 which is not on this chart. For all intents and
19 purposes Los Angeles and Basra are now sister
20 cities. Although this chart shows that LA is
21 comparatively less reliant on Saudi crude, Saudi
22 Arabia is still the number one foreign source of
23 oil for California.
24 A more recent analysis in the last few
25 weeks. We wanted to see what the impact of higher

1 oil prices last year and the recession might have
2 been on imports to see whether there may have been
3 a silver lining from the demand destruction on
4 consumption. Unfortunately what we found is that
5 it was all pain no gain and our imports from Iraq
6 and Saudi Arabia stayed relatively consistent and
7 our foreign oil imports also stayed relatively
8 consistent.
9 So we Californians really need to think
10 about petro-terrorism and the disruption to oil
11 supplies. Al-Qaeda is one group of many globally
12 that for political reasons engage in petro-
13 terrorism. They are very good at it. They have
14 been very effective in Iraq. They have also
15 attacked facilities in Saudi Arabia and carried
16 out attacks in Yemen.
17 And they tend to repeat their attacks on
18 targets. So for example, that attack in Saudi
19 Arabia on the Abqaiq facility wasn't as effective
20 but we expect them to attack again.
21 And I wanted to reflect a little bit on
22 what was mentioned earlier in terms of imports not
23 only from the Middle East but from West Africa and
24 Latin America. We should get specific.
25 You know, with regard to Latin America,

1 as I mentioned before, primarily those imports are
2 from Ecuador. Ecuador is not a reliable supplier
3 for California. They are antipathetic towards --
4 at least the government of Ecuador is antipathetic
5 towards the United States. They have been
6 nationalizing their oil assets. They kicked out
7 Occidental. And they have also have been known to
8 harbor FARC guerrillas, who are actually more
9 effective at bombing pipelines than Al-Qaeda is.
10 With regard to Mexico, at least in
11 Southern California, we don't get much oil from
12 Mexico. But were we to start to rely more on
13 Mexico, there have been attack by leftist
14 guerrillas. Very effective attacks that have
15 signatures of Al-Qaeda's tactics. So there is
16 information sharing that has been very effective,
17 whether directly or simply posted on the Internet
18 and shared that way. But those attacks in Mexico,
19 according to the Mexican government, did hundreds
20 of millions of dollars in economic damage per day.
21 And then with regard to West Africa. If
22 we were to become more reliant on Nigerian oil,
23 that may not be such a good idea. As you may know
24 in the last few years the tribal groups like MEND
25 have been extraordinarily effective at shutting in

1 oil production to the tune of, I think at this
2 point about 25 percent of oil production in
3 Nigeria is shut-in.
4 So that we are reliant on Middle Eastern
5 oil, and Iraqi and Saudi Arabian Oil, is not to be
6 solved by simply importing from other parts of the
7 world.
8 But getting back to Al-Qaeda, just as a
9 brief backgrounder. Their primary goal is to
10 drive the impure from the Islamic world and
11 establish a Caliphate. Impure would include us
12 Americans.
13 And their strategy has been explicitly
14 stated as bleed until bankruptcy, at least with
15 regard to the United States. They are going to
16 inflict unbearable costs on the US economy, erode
17 US public support for funding the war and
18 therefore stimulate regional withdrawal. And I'll
19 leave it up to you to see or decide how effective
20 they have been so far.
21 Their tactics are known as Fourth
22 Generation warfare. That was developed by the US
23 but now they claim it as their own and have
24 interpreted it in their own way and are very
25 explicit about it.

1 But the bottom line is that they are
2 very effective at using networks to strike from a
3 distance. Whether they are communication networks
4 or transportation networks or energy networks they
5 are very good at it. And again, it is political
6 and it is economic and it seeks to inflict
7 economic cost.
8 So how does that impact us? Well, as
9 has been said over and over in the last day, we
10 are heavily reliant on global supply chains. And
11 what we at CAST are looking at is, you know, is
12 that threat domestic or is that foreign or is it
13 both? And we tend to think that it's both. That
14 is to say, from an economic perspective and a
15 return on investment, which they are very explicit
16 about and I'll get to that in a bit in terms of
17 their analysis of attacks. It's cheaper to attack
18 overseas but hit us at home by disrupting those
19 foreign sources of oil.
20 And so more on ROI. Of course return on
21 investment does correlate with the price of oil.
22 And we saw increased attacks globally but
23 certainly in the Middle East when the price of oil
24 was higher. They are explicit about this. I
25 mean, these are very smart, sophisticated people

1 who are looking at costs and benefits just as we
2 might from a policy perspective.
3 And so a higher return on investment,
4 that is to say a higher oil price or reducing
5 costs, increases their incentives to attack. It
6 sounds extremely simple, and I guess it is, but it
7 also is common sense. So right now with the price
8 of oil a little bit lower, or a lot lower
9 certainly than last summer, we think there may be
10 less incentive to attack.
11 And in terms of the final bullet point.
12 You know, I just want to emphasize that we are not
13 criticizing US foreign policy here. We are
14 looking at what may be, and therefore what the
15 threat may be, to domestic oil supplies with
16 regard to foreign policy.
17 So if we are to withdraw our forces from
18 Iraq we think that raises the potential of a lower
19 cost for an attack by, by anybody who wants to
20 engage in an attack on oil infrastructure in Iraq.
21 And higher oil prices projected by simply looking
22 at the NYMEX futures market, an increase of about
23 40 percent to about $70 a barrel by the end of
24 2011 when we are projected to have pulled out
25 entirely.

1 So that's just simple math. And it may
2 be a simple analysis. And again, this is a work
3 in progress. But that would be a higher return on
4 investment for anybody who wanted to attack.
5 And this is not just Al-Qaeda, there are
6 many other groups who are engaged in fighting over
7 oil assets in Iraq. So overall we just think that
8 it may increase the threat of disruption. I mean,
9 it's something that we Californians need to
10 prepare for.
11 So again, you know, the approach that we
12 take is that we believe that California needs to
13 build resilience. And thankfully from a policy
14 perspective that has been very much California's
15 state of mind on a lot of different fronts,
16 beginning with earthquake preparedness, and
17 generally speaking, in terms of emergency
18 management.
19 So as California has been on the leading
20 edge of that sort of thinking with regard to other
21 crises, we just suggest that the CEC and other
22 California policy makers consider applying that
23 thinking to disruptions in the oil supply chain.
24 One way of doing that is of course
25 reducing consumption. And we certainly advocate

1 that. As much as I am standing up here and
2 suggesting SPR-West, I drive a car that runs on
3 biodiesel. And I think that California has
4 certainly been on the leading edge of trying to
5 develop policies to reduce consumption.
6 Unfortunately, reducing consumption
7 doesn't necessarily mean reducing imports. And
8 this chart is based on CEC staff analysis on AB
9 1493. And we applaud these efforts but we are not
10 sure whether they are going to be effective in
11 solving the problem of oil supply disruption from
12 foreign sources.
13 And so in the meantime while we are
14 working out these policies to try to reduce
15 consumption we think we should plan as well for a
16 disruption in a more immediate way and that is to
17 say, build SPR-West. And obviously it will take
18 some federal dollars. But the federal dollars
19 that it will take are less than we are currently
20 spending on a monthly basis in Iraq. So we think
21 those can be justified. Thank you.
22 VICE CHAIRMAN BOYD: Thank you. A quick
23 question if I might. To what extent are you aware
24 that there is discussion of this issue at the
25 federal level, i.e. the West Coast isolation and

all that you have laid out for us?

MR. JACOBSON: We think that there has been a bit of discussion at DOE but unfortunately it has not been made a priority. And as has often been the case, the East Coast doesn't really make the West Coast a priority in terms of policy making and spending dollars.

VICE CHAIRMAN BOYD: You mean the Left Coast, as they call us.

MR. JACOBSON: Yes.

PRESIDING MEMBER BYRON: And we return the favor too.

ADVISOR BROWN: I had a question too. Are you advocating a physical reserve or a paper reserve?

MR. JACOBSON: A physical reserve.

PRESIDING MEMBER BYRON: Commissioner Boyd, are we losing you shortly? Are you here for a few more minutes? Can you entertain a few more questions on this topic?

VICE CHAIRMAN BOYD: Yes.

PRESIDING MEMBER BYRON: Okay.

VICE CHAIRMAN BOYD: I do have to leave shortly.

PRESIDING MEMBER BYRON: This was a very

1 interesting presentation. And while you were
2 making it I was sitting here realizing that as
3 much as I don't like to talk about the subject I
4 have read some interesting books on it recently.
5 But some questions came to mind.
6 In fact, I am reading one right now on
7 the bombing of the LA Times building. The crime
8 of the century last year that killed 22 people.
9 Of course that was domestic terrorism, which leads
10 to my first question. Does the recommendation
11 that you are making apply as well to other forms
12 of terrorism that we should probably be concerned
13 about as well, domestic terrorism?
14 MR. JACOBSON: Yes. I mean, in terms of
15 resilience, yes, absolutely. You cannot harden
16 all targets. You need to -- a lot of it has to do
17 with preparing people to rebound. And so yes, we
18 are big advocates for that.
19 PRESIDING MEMBER BYRON: Well, and you
20 know, we have other vulnerabilities that we deal
21 with as well in our energy infrastructure. Does
22 your organization deal with or concern itself with
23 the electric supply and delivery exposure?
24 MR. JACOBSON: This analysis does not
25 apply to that but yes we have.

1 PRESIDING MEMBER BYRON: Okay. I would
2 be interested in some more information on that as
3 well from CAST.
4 MR. JACOBSON: Okay.
5 PRESIDING MEMBER BYRON: And other
6 question that came to mind is why don't you also
7 recommend we open up access to other domestic
8 supplies here in the United States?
9 MR. JACOBSON: Well we are not opposed
10 to that. We just are simply trying to focus on
11 what we think is the low-hanging fruit. And given
12 the political mine field that is opening up
13 offshore drilling, we think that it may be easier
14 from a policy perspective to at least get federal
15 and state policy makers to agree to build out this
16 reserve first.
17 PRESIDING MEMBER BYRON: But it seems to
18 me it only addresses the tip of the iceberg, if
19 you will.
20 MR. JACOBSON: Yes.
21 PRESIDING MEMBER BYRON: Once we finally
22 have the reserves here in the United States.
23 MR. JACOBSON: Well, those reserves will
24 be depleted over time as well. And so we think
25 that -- well first of all there are no silver

1 bullets here. We are not saying that this is the
2 core solution to our problems. What we are saying
3 is that this simply builds surge capacity so that,
4 so that in the event of a disruption the economic
5 costs won't be as severe while different
6 stakeholders seek to reallocate oil supplies to
7 California again.
8 PRESIDING MEMBER BYRON: Well thank you
9 for your presentation and thanks for coming.
10 MR. JACOBSON: You're welcome.
11 PRESIDING MEMBER BYRON: Commissioner
12 Boyd, I am going to suggest we take a break just
13 for a couple of minutes. But before we do I think
14 we may be losing you. Did you have any comments
15 you wanted to make?
16 VICE CHAIRMAN BOYD: Well, were I to
17 make comments it would just be to thank everybody
18 so far. Apologies to the other speakers but I
19 know they are in good hands with you and the rest
20 of the folks. This has been very interesting to
21 me. I don't have any findings as such. I think I
22 have a long laundry list of things we need to
23 pursue.
24 This last issue is one we have talked
25 about before when we debated the wisdom of a

1 strategic finished fuels reserve several years ago
2 so it's not the first time we have talked about
3 this. But the world has changed quite a bit so I
4 think we will have to talk more about it.
5 Otherwise, thank you.
6 PRESIDING MEMBER BYRON: Thank you,
7 Mr. Jacobson.
8 MR. JACOBSON: Thank you.
9 PRESIDING MEMBER BYRON: We are going to
10 take a ten minute break out of necessity. We will
11 start promptly at 11:10. Thank you.
12 (A recess was taken off the
13 record.)
14 PRESIDING MEMBER BYRON: Let's go ahead
15 and start since I said we should start promptly at
16 11:10.
17 We have I think one more session to go
18 through on petroleum and renewable product
19 pipelines and then some opportunity for public
20 comment. Gordon, would you go ahead and do the
21 introductions for this session.
22 MR. SCHREMP: In fact I will do more
23 than that, Commissioner Byron. I will provide a
24 little bit of context with some background as I
25 did with crude oil but not as many slides.

1 So just to I think reiterate some of the
2 theme that has been circulating the last day and a
3 half. California, with regard to transportation
4 fuel, and other forms of energy, it's a regional,
5 it's a regional supply/demand center, essentially.
6 We and other states are interdependent on one
7 another for supply.
8 California is primarily a source of
9 supply for the neighboring states of Nevada and
10 Arizona. And that's very important because that
11 affects how much petroleum products are moving
12 from California to those two states. and that in
13 effect has a demand draw on imports through our
14 marine infrastructure and pipeline infrastructure.
15 So that's why we pay attention to it. But there
16 is even a larger interstate regional supply/demand
17 balance interdependence.
18 This is a focus of, this is a Kinder
19 Morgan map of their system. We saw some of this
20 yesterday. But the map depicts the green line
21 that goes into the Las Vegas supply region, which
22 is predominately most of the product that goes
23 into Nevada.
24 There's a line that goes into Reno. And
25 then the lower red lines are the supply pipeline

that into Phoenix from the west, we refer to it as the West Line. And the two lines you see coming from El Paso, Texas all the way into Tucson, those into Phoenix, those are actually referred to as the East Line. And this is important because that line was actually expanded recently and had an impact on the supply/demand balance.

So we work with Nevada and Arizona to look at their demand forecasts. We sort of developed that together, working with them to obtain information. And we estimate what their demand will be for all primary forms of fuel, gasoline, diesel and jet fuel.

We look at that demand and we say, well how will that be met? Well for Nevada primarily the list point would be through pipeline exports from California to that state. But with the announced project of a Utah to Northern Las Vegas pipeline that will change the supply demand outlook if in fact that project does move forward. But we do plan on obtaining some information from Holly Energy Corp. on that project. They were unable to speak today, unfortunately, but they can provide some information on the status of that project as far as the IEPR process.

1 Arizona is supplied from two different
2 regions. Duane Yantorno, the next speaker, will
3 address that in more detail. But a key take-away
4 is when you look at this slide is all of the
5 transportation fuels we have exported to the
6 neighboring states, Nevada and Arizona.
7 As you can see there has been a decline
8 since the peak in 2005. And why I titled the
9 slide Indirect Supply, that's exactly the effect
10 it had. As our exports declined to those two
11 states more petroleum products were available for
12 use in California and it took a little bit of
13 pressure off the marine import infrastructure.
14 So this indirect supply was almost
15 exclusively a consequence of the East Line being
16 expanded in capacity. And what happened is more
17 supply started flowing from West Texas going into
18 Arizona than out of California. And the supply
19 shift was rather dramatic. In 2002, 63 percent of
20 the petroleum products supplied to Arizona were
21 from the west, from California and/or through
22 California marine infrastructure. Today, or more
23 recently in 2008, that number is down to 34
24 percent.
25 So that's been a rather significant

1 supply shift that's about 76,000 barrels a day and
2 more supply available to the California
3 marketplace. So that's really been a part --
4 that's been part of, I think, the oversupply if
5 you will and the lowering of the refinery margins
6 most recently. That's been one of the
7 consequences of this oversupply situation and
8 lower crude oil runs at California refineries.
9 That lowered utilization rates.
10 So the reduction you see in this chart
11 is primarily because of that. Because in fact the
12 deliveries into Arizona from 2006 to 2008 by
13 pipelines from both directions are about equal.
14 So the decline isn't because of reduced demand in
15 Arizona, necessarily. It's because of this supply
16 shift. That's market participants deciding it's
17 more cost-effective to supply from the east rather
18 than the west.
19 So just to reiterate. We will be
20 looking at what those projections are for demand.
21 We will be looking at new projects.
22 Both the Utah to Las Vegas pipeline and having it
23 as a scenario. What the impacts are on the
24 outlook for the pipeline exports.
25 And we will also be including other

1 expansion projects. The one mentioned yesterday
2 by Kinder Morgan is the increased capacity on
3 their pumping rates from California into Las
4 Vegas.
5 We heard a little bit about this on Day
6 1 but I just want to reiterate what Kinder Morgan
7 was expressing and sort of sum up. Yes, they move
8 some ethanol in some of their pipeline systems in
9 other parts of the US, that's correct. Have they
10 moved some biodiesel, B2 or B5 blends? Yes they
11 have. But there are caveats to that.
12 From what they were describing yesterday
13 it seems unlikely those means of conveying
14 renewable fuels through mixed product pipelines is
15 unlikely to be utilized in California.
16 Therefore staff will continue with
17 regard to our assumptions that incremental
18 throughput of renewable fuels will have to be
19 accomplished at distribution terminals by
20 increasing the capacity to receive truck-borne
21 cargos of renewable fuels as well as additional
22 storage tanks to store them.
23 So unless Kinder Morgan provides
24 additional information that they plan to move
25 biodiesel in their California systems or ethanol,

that will be essentially our assumptions in the analysis.

The two speakers we have following me are Duane Yantorno from the Arizona Department of Weights and Measures and Steve Sokolsky from CALSTART. And I believe we have -- Duane is on the line.

MR. YANTORNO: Yes I am, Gordon.

MR. SCHREMP: We are just going to call up your presentation here. I'll be the slide controller and you just tell me when you would like to move on to the next slide.

MR. YANTORNO: Thank you, Gordon.

Good morning, Commissioners. My name is Duane Yantorno. I am the director of transportation fuels and air quality programs for the Arizona Department of Weights and Measures. I would have liked to have been there today with you but as you know state budgets are really tight and so travel isn't allowed; but I have been enjoying the webcast. And the information being presented by the presenters has been really valuable information for us.

As Gordon had indicated earlier, there is a strong interdependence between Arizona,

1 California, Nevada, New Mexico, West Texas. And
2 so we look forward to working closely with the
3 California Energy Commission on these kinds of
4 issues. Next slide.
5 As you can see supply to Arizona comes
6 from two major pipelines, as Gordon had alluded
7 to. There's the West Line out of Southern
8 California and the East Line out of West Texas.
9 In addition to that supply is brought in out of
10 the Gulf Coast through the Longhorn Pipeline and
11 we will talk more, a little more about that.
12 The majority of the fuel coming into the
13 state comes in through these pipelines. We do
14 receive some rail shipments to smaller
15 distribution centers in the northern part of the
16 state. We also receive some shipments or
17 deliveries directly to retail out of the
18 neighboring states, California, New Mexico and
19 Nevada. Next slide.
20 I want to talk a little bit about, about
21 the timeline associated with this shift in supply.
22 As Gordon had alluded to, this shift occurred.
23 And it was good news for California but created
24 some issues for Arizona.
25 The timeline associated with this. It

was back in July of 2003 when the Kinder Morgan East line between El Paso and Tucson had ruptured in Tucson, spraying some houses down with gasoline.

It had a significant impact on Arizona's cleaner burning gasoline, CBG, coming from the East Line when the East Line was shut down. We'll talk about CBG simply because CBG represents 70 percent of all the gasoline demand in the state. And so the effects -- the effects on CBG are felt first before we see that on the other more traditional transportation fuels.

The Governor established a task force to take a look at the pipeline systems and to make recommendations to her. The task force looked at not only the pipeline and transportation fuels but other forms of energy supplied to the state. To make recommendations to help make it more secure. As you know we saw some real problems in Phoenix when the supply was cut off and we saw runs on gas stations, fistfights and just real overall problems in 2003. Next slide.

The task force made a recommendation to support the Kinder Morgan expansion of the East Line. Kinder Morgan at that time agreed and said

1 that, be careful what you wish for. If we had it
2 to look back we would probably still support the
3 expansion but we would have been a little bit more
4 prepared for what we saw as a result of that.
5 Kinder Morgan developed a two-phase
6 expansion schedule. The first phase was to
7 increase the line size and to build breakout
8 tankage in El Paso.
9 The second phase was to add pumping
10 capacity.
11 At about the same time that we saw this
12 increase in capacity of the East Line we also saw
13 increased shipments on the Longhorn Pipeline into
14 El Paso. Next slide.
15 Phase 1, the expansion was completed in
16 July of 2006.
17 Phase 2 was then completed in December
18 of 2007. And so you'll see a little lag time in
19 2006 because they had, they had to overcome some
20 of the start-up problems that they experienced
21 with Phase 1. Next slide.
22 What we saw as far as the shift in
23 supply distribution. In July of 2003 at the time
24 of the East Line pipe failure we saw 53 percent of
25 all CBG coming into the state coming in out of the

1 West Line; 42 percent was coming in off of the
2 East Line.
3 In November of 2006, after the Phase 1
4 completion was done, we saw the shift to the East
5 Line of 68 percent and the West Line now only
6 supplying 32 percent.
7 We expected that to kind of hang out
8 there at that point. But with the completion of
9 Phase 2 in January of 2008 we saw a shift of 80
10 percent coming in off of the East Line and only 20
11 percent coming off o the West Line.
12 And we'll talk about some of the effects
13 that we saw as a result of this shift.
14 In December of 2008 we saw, when Flying
15 J filed for Chapter 11 protection, we saw 10
16 percent coming off of the West Line and 90 percent
17 off of the East Line.
18 Currently today, as of February, that
19 supply shift has shifted back towards the West
20 Line a little bit more. We are at 42 percent off
21 of the West Line and 58 percent off of the East
22 Line. So that kind of shows what impact the
23 Flying J and their supply problems resulted in
24 coming into Arizona. Next slide.
25 This is a graph that we have been

1 tracking supply off of the East and the West
2 Lines. As you can see we have identified where
3 Phase 1 was, we have identified where Phase 2 was,
4 and some other supply disruption significant
5 events.
6 As you can see there you saw the shift
7 to the East Line. The yellow is growing as we
8 move forward from Phase 1. You see and you may
9 note that at about March and April of 2007 you see
10 a sharp increase in West Line delivery. That even
11 is specifically related to us losing one of the
12 three refineries on the East Line for supply, and
13 that was the Valero McKee explosion which took
14 them offline for CBG supply. Next slide.
15 What you see here is Kinder Morgan was
16 right. We needed to be careful for what we wished
17 for. Clearly this created some problems for
18 Arizona.
19 The East Line refineries. It's clear
20 that the market for the East Line refineries and
21 the Gulf Coast is preferential to Arizona. And so
22 we saw that significant shift.
23 The economics were such that they could
24 make a lot more money shipping into Arizona than
25 they could going into Dallas or some of the other

1 markets that they would normally have supplied to.
2 In November we were up to 90 percent
3 based upon the East Line, coming off of the East
4 Line. And that was tied to three refineries and
5 one registered supplier on the East Line.
6 So what this has done is this created a
7 sensitivity for CBG supply. And I'll talk a
8 little more about that. Next slide.
9 Originally Arizona's supply was
10 dependent, back in 2003, basically upon eight
11 refineries off of the East Line -- off of the West
12 Line, excuse me, out of Southern California, and
13 one refinery out of the San Francisco area. So
14 supply problems could be spread out over the eight
15 refineries.
16 Now supply is simply supplied by three
17 refineries with one registered supplier who has
18 now reduced this amount of supply simply because
19 of them filing Chapter 11 protection. So we have
20 now shifted our dependency on supply from eight
21 refineries to three refineries. Next slide.
22 Some of the other problems that we saw
23 as a result of this is we saw an increase in the
24 transit time on the West Line because of that
25 reduction, as Gordon had indicated, of 34 or 35

1 percent coming off of the West Line. There wasn't
2 enough product to move it as rapidly so Kinder
3 Morgan slowed the line down. We actually saw
4 times when the West Line had to be shut down for a
5 time because there wasn't product available to be
6 able to push product into Phoenix.
7 Another problem of the shift we saw that
8 was the breakout tankage that was originally in
9 Tucson for the East Line CBG has been removed and
10 now that is a direct line directly from El Paso
11 into Phoenix. This reduced some of our
12 flexibility as we saw in 2003. We were able to
13 pull some supply off of the East Line. We could
14 get it into Tucson and then offload it into trucks
15 and deliver it into Phoenix. That flexibility has
16 been lost now.
17 Ultimately what we found is we saw an
18 increase in the volatility of pricing and supply.
19 More sensitivity to scheduled down time on the
20 three refineries on the East Line. And
21 specifically significantly affected by down time
22 as a result of unscheduled down time on those
23 three refineries. Next slide.
24 One of the other problems we saw with
25 the expansion of the East Line and it was unique

1 that we had to deal with. Because of the
2 regulatory requirements for Arizona CBG and the
3 fact that it has to be, it has to come in at
4 specific timing, Longhorn bringing product out of
5 the Gulf Coast ended up with scheduling problems.
6 And the transit time originally out of the Gulf
7 Coast to El Paso was 30 days.
8 At their peak they were able to reduce
9 that transit time to 14 days.
10 But any delay at all in that transit
11 time could result in the product being non-
12 compliant. And as a matter of fact we saw.
13 Gordon, if you want to go to the next slide.
14 We saw that as a result of Ike. And so
15 some of the things that we have seen in May of
16 2007 -- 2008. On May 7, 2008 Navajo went down
17 unexpectedly when they were having problems with
18 their unit.
19 During 2008 the hurricane impacts. And
20 this is interesting because what had happened was
21 at one point in time there was almost half a
22 million barrels of CBG that was stranded in the
23 Longhorn Pipeline as a result of Hurricane Ike.
24 When it shut down the Gulf Coast it shut down the
25 Longhorn Pipeline.

1 As a result of that, that fuel would
2 have come in and would have been non-compliant.
3 The impact was almost a five day supply that
4 wasn't going to come in. When we conducted our
5 analysis of what the supply impact would be we
6 determined that we would be down to about a day, a
7 day and a half of supply here in Phoenix.
8 We contacted EPA. We then let them know
9 that this was going to be a problem. EPA then
10 issued, granted one of the last waivers, if not
11 the last waiver as a result of Ike so that we
12 could move our fuel standards for the Phoenix area
13 out by two weeks, which would have allowed that
14 transition fuel to go ahead and continue to come
15 in. And it was just the compliance date at retail
16 that we were requesting a waiver for. And so it
17 was effective and we were able to do that.
18 The other thing that we have seen and we
19 see that now is that on December 22 Flying J filed
20 for Chapter 11 protection. They were a major
21 supplier on the East Line; they were a major
22 supplier out of the Gulf Coast. As a result of
23 that we saw a shift in supply. And again you saw
24 that. We are currently looking at a little better
25 distribution of supply off of the West Line. Next

1 slide.

2 The other issue that we found is that as

3 you know, this industry is very economics driven.

4 When supply actually -- when the price goes up

5 then supply will shift. We saw this in -- earlier

6 this year, okay, in January. I think it was

7 January when we saw a 40 cent difference between

8 CARB gasoline and Arizona gasoline. At that time

9 we saw a significant shift of supply off of the

10 West Coast and that continues to this day.

11 MR. SCHREMP: Duane, just to interrupt

12 you. When you say a difference you mean the

13 prices in Arizona were 40 cents higher than

14 California?

15 MR. YANTORNO: That is correct. And

16 that gave the incentive for West Line suppliers to

17 go ahead and supply Arizona CBG instead of

18 producing CARB gasoline. And so with that being

19 said, okay, one of the things that we found is

20 that the supply of CBG now is coming from a

21 different group of people. Not specifically

22 refineries but more what I call marketer/blenders.

23 You want to go to the next slide.

24 Again this just shows you supply. I

25 just wanted to reiterate what we had seen with

1 regards to Ike, Flying J. The impact that the
2 bankruptcy had on our supply levels. Next slide.
3 And so one of the -- when we talked to
4 the Governor's Office about this problem, okay,
5 and this increased sensitivity to supply
6 disruption we looked at what the options would be.
7 And understanding the state has no, I don't know
8 what you want to call it, no authority to force
9 these kinds of things to happen.
10 But we looked at boosting the amount
11 coming from the West Line. All we could do is we
12 notified West Line refineries that this imbalance
13 existed. That that sensitivity to supply exists.
14 And that for purposes of protecting supply they
15 may want to shift some of their supplies to the
16 West Line so that they aren't totally dependent
17 upon the East Line for supply. All we did is
18 communicate that. That's all we were able to do.
19 Increase the number of Gulf Coast
20 registered suppliers. We tried to do that. We
21 tried to encourage Gulf Coast registered
22 suppliers. What we were trying to get to was
23 creating a dependency on more than just three
24 refineries and we have done that. Again, we have
25 increased Gulf Coast registered suppliers but

1 again, they are basically coming from the
2 marketer/blender types and not specifically from
3 refineries.
4 The other thing we wanted to look at was
5 expanding storage capacity to mitigate any
6 prolonged supply problems. That has been done.
7 We have expanded supply -- we have expanded
8 storage capacity at the Phoenix terminals. That
9 was, again it was based upon economics and it was
10 based upon one of the terminals wanting to help
11 with this supply problem. And so they did that
12 and expanded their capacity. And that helps.
13 That helps to expand it to days of supply are
14 closer to five days now as compared to three and a
15 half. Next slide, Gordon.
16 What we have seen, and I have talked
17 briefly about this, is that with this decrease in
18 demand that has helped mitigate the effects and
19 the increase in storage capacity. So where we are
20 at about 100,000 barrels a day, 108,000 barrels,
21 that allows us the ability to store more and to
22 help mitigate some of the impacts. The problem is
23 that we are dependent upon the economics. More so
24 now because the marketer/blender types are looking
25 to make money. And if the economics shift they

1 will be the first ones to pull out of supplying
2 the Arizona market CBG.
3 The additional, one of the additional
4 benefits that we found is that the lower demand
5 has allowed for refineries to operate at decreased
6 throughput rates, which ultimately gives them the
7 opportunity to supply incremental barrels when
8 demand calls for it. That's a good thing. The
9 one problem that we have found is that the
10 increased transit time on the west like results in
11 a slower reaction time to that demand if in fact
12 it was needed. But we'll see what happens.
13 We did see an increase, specifically an
14 increase in rail demand and rail deliveries of CBG
15 out of the Gulf Coast. This wa the preferred
16 method for delivery considering that Longhorn was
17 having problems meeting their schedule and their
18 commitments.
19 And that's pretty much where we are.
20 All these things still affect supply. And again,
21 the economic shift, we could see that shift
22 directly back over to the East Line at some point
23 if the economics were to shift against supplying
24 Arizona CBG off of the West Line.
25 That's pretty much my presentation. If

1 you have any questions I'll be willing to answer.
2 PRESIDING MEMBER BYRON: Mr. Yantorno,
3 this is Commissioner Jeff Byron. Thank you very
4 much for joining us today, for giving up your
5 lunch hour there in Phoenix. I was not aware of
6 this issue at all going on in Arizona. I was
7 writing down questions as you spoke and you tended
8 to answer all of them as we went along.
9 It is kind of interesting that it is not
10 quite the result you would expect with increased
11 access to other markets that it created these kind
12 of shortages. I keep coming back to storage. The
13 storage might be your most helpful friend here in
14 terms of mitigating some of these problems. Is
15 that, is that how you see it?
16 MR. YANTORNO: Absolutely. And I think
17 that again the economics drive that. They aren't
18 going to build storage if they can't fill it. And
19 so what we have seen is that increase has helped.
20 Additionally there are other terminals in the
21 Phoenix area that are looking at increasing their
22 storage capacity as well.
23 And you're right, the economics drive
24 everything with regards to this industry. At this
25 point in time you can't go to the West Line

1 refineries and say, you have got to supply us with
2 more fuel because it just won't happen. The good
3 thing is, is that it helped California.
4 PRESIDING MEMBER BYRON: Well thank you.
5 MR. YANTORNO: I will really be
6 interested to see the Kinder Morgan CalNev
7 expansion and what impacts that has on the Nevada
8 market as well as supply coming out of California.
9 PRESIDING MEMBER BYRON: All right. So
10 I'd like to ask, is there anything else or any
11 other recommendations that you have for us here in
12 California as they affect you?
13 MR. YANTORNO: I think the biggest thing
14 is already being done, the open lines of
15 communication. As Gordon had said and we agree
16 100 percent is the interdependency that we have on
17 each other. Without those open lines of
18 communication you can't see what impact is coming
19 your way. And so I think that we continue to work
20 as part of a group that Gordon has put together.
21 Work with them and the surrounding states. And I
22 think that's probably more critical.
23 PRESIDING MEMBER BYRON: You seem to
24 imply that's fairly new. Gordon, is that new or
25 something you have been doing for a long time.

1 MR. SCHREMP: Duane is referring to the
2 western states coordination meetings that we
3 conduct once a month, which is an overview of US
4 and regional transportation markets.
5 We also now are talking about
6 electricity and natural gas, what sort of the more
7 recent price and supply situations are. We talk
8 about renewable fuels, level of profitability at
9 biorefineries, supply/ demand balances for
10 ethanol, and in the future. We have been doing
11 this, conducting this meeting for, I believe --
12 what is it Duane, about almost a year now?
13 MR. YANTORNO: Almost a year. I think
14 it's about eight, nine months.
15 PRESIDING MEMBER BYRON: Very good.
16 Well let's add electrical transmission lines to
17 the list then too.
18 MR. YANTORNO: I think that's a good
19 idea.
20 PRESIDING MEMBER BYRON: All right.
21 Well thank you very much for joining us today.
22 MR. YANTORNO: Well thank you for having
23 me. I have appreciated it a lot, thanks.
24 MR. SCHREMP: Thanks, Duane. You will
25 be hearing from me next week at our next meeting.

I think we will probably put you on mute right now but we will be circling back to you to work with you as we develop sort of that regional supply/ demand forecast.

MR. YANTORNO: Okay, thanks, Gordon.

MR. SCHREMP: Our final speaker today will be Steve Sokolsky from CALSTART.

MR. SOKOLSKY: Thanks, Gordon. Contrary to popular belief and the agenda I am not Bill Zobel of Sempra. Bill was unavailable. But we at CALSTART share a lot of the concerns and interest in biomethane that they do at the utilities, especially at Sempra.

So Bill asked us to pinch hit for him and give a basic overview on what some of the resource potentials are for biomethane and where it could be applied. Not only in pipeline issues but also from what we are interested in, is the transportation issue and how biomethane could be used as a renewable source of either liquified or compressed gas.

For those who are not familiar with CALSTART. We are a nonprofit, clean transportation consortium that is doing everything it can to advance the clean transportation

1 industry through information, value added
2 services, assisting in the development of
3 technologies through worker -- through end-user
4 groups and stakeholder groups. We do one-on-one
5 consulting with fleets to advance their policy
6 choices. And we work here in Sacramento very
7 often to get the policy choices advanced and bring
8 new perspective to the policy choices that the
9 state is making.
10 I am going to talk about biomethane,
11 which is basically a gas that is created from a
12 bio-source. And when I discuss this it is
13 important to remember that biogas or biomethane is
14 the same as natural gas. It's both methane, it
15 has the same chemical contribution.
16 The difference is that biogas has a
17 renewable source, a bio-source and it has zero or
18 possibly even negative greenhouse gas emissions.
19 If you see the latest ARB in the AB 118
20 proceedings and also in the Low-Carbon Fuel
21 Standard proceedings, biomethane scored extremely
22 well in terms of greenhouse gases per energy unit.
23 But the idea is that whether it is a
24 natural gas from a fossil source or from a bio-
25 source it can be injected into the same pipeline

and used for the same end uses, whether it be residential, industrial. And what we are interested in is bringing the transportation component into it. So having biogas as a source of either liquified or compressed natural gas adds to that supply of gas for transportation use.

The process for creating biomethane is the same whether the source is a dairy, a farm, municipal solid waste, a wastewater treatment plant. But basically, whatever the feedstock, it can be digested through an anaerobic digester. Which there are different types. Whether a covered lagoon or a flow plug unit. But this will, through the process can create biogas from this organic waste. A byproduct of this could be bio-fertilizer, which is used often at the dairies and the farms.

That digester gas now can be either used right there at the facility for a combined heat and power unit and produce electricity and heat right there for the facility's use. It can be further upgraded by removing the CO2, nitrogen and some of the other inerts and that upgraded gas can be brought up to pipeline quality.

Basically it meets all of the PUC's

1 requirements for Rule 21 or Rule 30 so that it can
2 be used in the pipelines. And can be either
3 injected and become a regular pipeline use or it
4 can be used for transportation uses. And as a
5 liquid fuel it can be transported to other
6 stations or it can be compressed and used either
7 at the facility or -- mostly at the facility for
8 the facility's fleet.
9 We have been asked by Sempra and others
10 to look at some of the biomethane potential in
11 California. We looked at a couple of sources.
12 And there is some disagreement, and this is a good
13 disagreement, between what the potential of
14 biomethane resource is in California. UC Davis
15 did a study a few years ago and I'll show you
16 something that the bioenergy plan from the Energy
17 Commission here did in 2006.
18 But even though we have differing
19 numbers they are both pretty high. The gross
20 methane potential from bio-sources in California
21 has been estimated by UC Davis at about 125
22 billion cubic feet per year.
23 Of that about 23 billion cubic feet
24 seems to be technically feasible, which means that
25 it is economically available. It is easy to

1 obtain and to upgrade and transport.
2 From dairy waste alone it has estimated
3 that 14 billion cubic feet is available from bio-
4 sources.
5 So when we at CALSTART are looking at
6 this from a transportation component, we estimate
7 that using natural gas as a fuel, that can fuel
8 approximately a quarter of a million cars.
9 The Biomass Fuels Study here at the
10 Energy Commission in 2006 has slightly different
11 numbers but still they were very, they are still
12 significant to show that the potential, when
13 compared against diesel that is used in
14 California, the combination of biomethane and
15 thermal biofuels, which is basically biosyn gas,
16 can basically compete significantly with the
17 diesel that is used. A combined 2.6 billion
18 diesel gallons a year.
19 We are interested, of course, in looking
20 at the dairies and seeing what they can do and
21 what they can contribute. And using this example.
22 Just in Tulare alone -- Tulare has been called the
23 Saudi Arabia of cows.
24 (Laughter.)
25 MR. SOKOLSKY: But you can see from a

1 transportation component you could fuel just from
2 the dairy biomethane creation in that area, 30,000
3 cars could be fueled just in the Tulare area. And
4 we did some mapping here with the current stations
5 that are dispensing CNG. And just in those three
6 mile concentric circles there are, there's a lot
7 of biomethane available from dairy sources.
8 We are currently partnering with other
9 organizations to do the first transportation
10 demonstration project. One of the dairies in the
11 area around Lindsay, which is Hilarides Dairy, is
12 ow running compressed natural gas trucks that are
13 running on compressed biogas.
14 They are using the dairy itself to run
15 feed and milk product up and down Route 99. They
16 put a lot of miles on. But we are going to test
17 those vehicles to make sure that the emissions and
18 the performance are comparable to other natural
19 gas vehicles and to diesel vehicles to see what
20 the actual benefits are.
21 But the next step in this project will
22 be moving it -- a similar demonstration at a
23 central facility at Hilmar Cheese near Modesto,
24 which can fuel fleets from many different
25 facilities, both dairies and other truck fleets.

1 So using the gas as created there it could be a
2 central fueling location for biogas.
3 There's different benefits from
4 biomethane, biogas. That not only can it be used
5 at a facility that could be off the grid and used
6 to power that facility or even power the trucks
7 for that facility. But it is also, after it is
8 upgraded, can be used for pipeline injection.
9 PG&E is working in that direction right
10 now with Microgy. It's seven different dairies.
11 They have started construction of their upgrading
12 equipment recently. They should be only hopefully
13 later this year. But PG&E is very interested in
14 this because it helps them meet their Renewable
15 Portfolio Standards. So this is a very good
16 byproduct of the creation of biomethane and
17 biogas.
18 In addition to dairies the other sources
19 for biomethane are landfills and wastewater
20 treatment plants. Landfills, just to give an idea
21 of how much the potential is. One pound of
22 municipal solid waste in a landfill creates .1
23 cubic feet of landfill gas right there every year.
24 We looked at it from a transportation
25 aspect and we saw that some of the projects that

are going on now to do gas upgrading at landfills in California, we could get the equivalent of more than 25,000 gallons of diesel equivalent gallons per day of either CNG or LNG from some of these projects. The most promising one is at Altamont where Waste Management will be putting in a large upgrading facility and fueling their trucks there, which is going to open later this year.

Wastewater treatment plants are also, it's a very, it's a good source for biogas. A hundred gallons of wastewater creates one cubic foot of biogas per day. So just looking nationally there are numerous, 16,000 in the country. And right now no one is really capturing and upgrading this, it is all being used at the facility, if it is being used at all.

I want to just touch briefly on biosyngas. I am not fluent on this issue but Sempra has investigated this and they think this is an area of additional research and consideration. Because the creation of syngas from a bio-source, think there is significant potential as related with the other biomethane creation.

The technology is feasible but still at

1 an uneconomic phase.

2 So they recommend that additional

3 research be done on both the technical and

4 economic issues and be incorporated into this

5 Committee's future work.

6 To give you one idea of what the

7 potential is for biomethane in transportation. In

8 Western Sweden biomethane powers more than one-

9 half of the sources of biogas, of natural gas

10 transportation in Western Sweden. I wish

11 Commissioner Boyd was still here because he could

12 probably do this presentation better because he

13 has seen all this, he knows it firsthand so he is

14 a great resource on this. But the idea that we

15 can learn a lot from what's going on in Sweden in

16 terms of capturing and utilizing biogas is

17 something that has a lot of potential for

18 California.

19 So finally I just want to highlight a

20 couple of the benefits of using green gas here in

21 California and nationwide.

22 It's a very strong environmental support

23 for natural gas vehicles by creating that cleaner

24 source of gas and also almost a negative

25 greenhouse gas potential for transportation use.

It's a great transportation transitional feedstock for hydrogen as we become more of a gaseous transportation fuel society. This is a good transitional feedstock.

As I mentioned the environmental benefits of not only natural gas but natural gas hybrids are increased by adding a bio component.

And then we can bring in even more through plug-in hybrids and hybrid EVs with natural gas.

And as I mentioned earlier, the utilities like this because it does meet their portfolio requirements for renewable.

And that's all I have to say, I'll answer any questions. But we think that this is something that should be on the Committee's radar. It deserves additional study in terms of what the actual resource potential is in California from all of these sources. What the effect would be on the pipeline system. Whether the utilities have the capacity to handle a lager amount of gas supply through bio-sources. And that it is something that California should be utilizing more as we have programs like the Low-Carbon Fuel Standard and AB 118.

1 So thank you for your time. We
2 appreciate the opportunity to speak today.
3 PRESIDING MEMBER BYRON: That was very
4 good. Thank you, Mr. Sokolsky.
5 A couple of quick questions. Of course
6 I think the reason probably, as you indicated, as
7 long as it is classified as a renewable fuel the
8 utilities are interested in it. Are you having
9 any difficulty or issues, are there any
10 outstanding issues in being qualified as pipeline
11 quality natural gas?
12 MR. SOKOLSKY: The technical issues are
13 not there. The technical issues have been solved,
14 mostly overseas. But it is mostly an economic
15 issue now and identifying the proper bio-source
16 and the size of the facility for the operating
17 equipment that is available. So technically it is
18 very easy to do. But it is whether it is
19 economical from a small farm or a small landfill,
20 is that better than a larger one. What are the
21 economics involved with each.
22 And that is probably the barriers that
23 need to be investigated more than the technical
24 barriers. Because there's plenty of technologies
25 out there to remove mostly CO2 from the raw biogas

to bring it up to pipeline quality and make it acceptable to the utilities for their transmission.

PRESIDING MEMBER BYRON: And of course removing -- my second question has to do with removing greenhouse gases. Are you getting credit when you collect methane from dairy waste as a GHG reduction?

MR. SOKOLSKY: There can be credits collected because the alternative is flaring the gas at the site of the creation of the biogas. So if it can be collected and used and then that credit can be collected either on the utility side or on the transportation side, those credits could be available.

PRESIDING MEMBER BYRON: Are they being, are they being considered under ARB's rulemaking, do you know?

MR. SOKOLSKY: From what I understand they are. I can't answer that precisely. But I understand they are considering that because the air districts are having problems with just the use of biogas in gen sets and combined heat and power at the facilities because they are, have very slightly higher NOx emissions.

1 PRESIDING MEMBER BYRON: Right.

2 MR. SOKOLSKY: So they are -- I know at

3 the district level they are very interested in

4 investigating biomethane more closely because they

5 will eliminate that local emissions problem. And

6 it could be more of a greenhouse gas strategy.

7 PRESIDING MEMBER BYRON: Yes, I have

8 heard about this. Thank you very much.

9 MR. SOKOLSKY: Thank you.

10 ADVISOR BROWN: I just wanted to make a

11 couple of comments. And first thank Steve. It's

12 always nice to see you, Steve.

13 MR. SOKOLSKY: It's nice to be home.

14 ADVISOR BROWN: On behalf of

15 Commissioner Boyd. This whole issue of biomass,

16 biopower and biomass is a very intense interest

17 area of his. We are actually having a workshop on

18 Tuesday, April 21, on some of these related issues

19 so we get to dig a little bit deeper next week.

20 I wanted to also comment that on the

21 issue of these dairy digesters. We have been

22 extremely active with Cal-EPA and other parties in

23 trying to get some of these regional collection

24 centers incented.

25 The issue, and I wanted to get Steve's

take on this. But as I understand it the issue is financial. Some of the projects in the Valley, some of the biogas projects such as the ones that PG&E is pursuing, are having difficulties getting financing right now.

MR. SOKOLSKY: That is exactly right.

ADVISOR BROWN: Along with everybody else, right, because of the economic downturn. And they are really looking for incentives, they are looking for economic stimulus money. And we are going to continue to pursue that. I for one am very appreciative, Steve, of this presentation because I think it solidifies our understanding of some of the issue.

MR. SOKOLSKY: To that point on the economics. We are putting together a biomethane jump-start proposal for some of these stimulus funds. That we are going to bring in companies like Microgy, some of the dairies.

And also I know Paul Relis from CR&R was here earlier today. They are recycling, they do a recycling facility in the Los Angeles area where biogas is created there also.

So there's a lot of sources available. And I think it is just identifying the most

1 economic source and the most economic upgrading
2 method and location.
3 ADVISOR BROWN: Right.
4 MR. SOKOLSKY: That is the key to this
5 and probably the linchpin.
6 ADVISOR BROWN: Thank you.
7 MR. SOKOLSKY: Thank you.
8 MR. SCHREMP: Thank you very much,
9 Steve. And yes, former California Energy
10 Commission employee.
11 Well I think at this juncture we would
12 like to open it up to any comments or questions
13 anybody in attendance may have here.
14 And seeing no rush to the podium I'll
15 turn to Nick. Are there anybody with questions
16 online?
17 MR. JANUSCH: No, unless they want to
18 talk right now.
19 MR. SCHREMP: Silence I guess answers
20 that question.
21 So I want to thank all of you for
22 attending today and certainly the presenters for
23 traveling here and putting the time in to put
24 their presentations together and conveying the
25 information. I'll turn the mic back over to

Commissioner Byron.

PRESIDING MEMBER BYRON: Thank you, Gordon.

You know, this was really an extraordinary day and a half. I sometimes use the line that working at the Energy Commission is like drinking from a fire hose. I think this was drinking from a, from a gas pump hose the last day and a half.

(Laughter)

PRESIDING MEMBER BYRON: And of course I don't know of any other state that delves into the details of subject matter like this so it is really a wonderful opportunity. I feel very fortunate to have been on the receiving end of so much good and sometimes troubling and thought-provoking material.

I would like to thank all of our speakers for the extraordinary efforts that they made to bring us up to date and help this Commission move forward in making recommendations in our Integrated Energy Policy Report.

I have taken a lot of notes and I have drafted up some recommendations. I think I should just call them thoughts at this point, that need

further vetting with the staff and my fellow Commissioners on the preparation of the IEPR.

Of course Commissioners Boyd and Douglas are very strong in the transportation fuels and infrastructure area and I will greatly be relying upon them.

But I would like to thank you all again. I would like to thank the staff for pulling together a very extraordinary agenda for us.

We are adjourned.

(Whereupon, at 12:06 p.m., the Joint Committee Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Joint Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 26th day of May, 2009.