

STATE OF CALIFORNIA - THE RESOURCES AGENCY
BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of,) Docket No. 11-IEP-1K
)
) Joint Integrated Energy
) Policy Report (IEPR)
Preparation of the) and Electricity and
2011 Integrated) Natural Gas (E&NG) Committee
Energy Policy Report) Workshop on Natural Gas Market
) Assessment Reference Case and
_____) Scenario Results

CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
First Floor, Hearing Room A
Sacramento, California

DOCKET	
11-IEP-1K	
DATE	9.27.11
RECD.	10.13.11

TUESDAY, SEPTEMBER 27, 2011
10:00 A.M.

Reported by
Kent Odell

ORIGINAL

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Commissioners

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Karen Douglas, Commissioner, IEPR Committee
Carla Peterman, E&NG Committee

Staff Present

Suzanne Korosec, IEPR Lead
Ruben Tavares
Leon BRATHWAITE
Ross Miller
Ivin Rhyne

Also Present (* by WebEx)

Dr. Kenneth Medlock III, Baker Institute at Rice University

Catherine Elder, Aspen Environmental

Mia Vu, PG&E
George Wayne, Department Head, Manager, Strategic
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Lee Bennett
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Bill Wood, CEC
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1 P R O C E E D I N G S

2 SEPTEMBER 27, 2011 10:04 A.M.

3 MS. KOROSEC: All right, I think we'll go ahead
4 and get started now that we have all of our
5 Commissioners. Good morning. I am Suzanne Korosec and I
6 manage the Energy Commission's Integrated Energy Policy
7 Report Unit. Welcome to today's workshop on Natural Gas
8 Market Assessment Reference Case and Scenario Results.
9 This workshop is being conducted jointly by the Energy
10 Commission's Integrated Energy Policy Report Committee
11 and Electricity and Natural Gas (E&NG) Committee.

12 Before I turn things over to the staff, I'll just
13 cover a few housekeeping items and talk a little bit
14 about how this effort fits in within the 2011 IEPR.

15 For those of you who may not have been here
16 before, restrooms are out the double doors and to your
17 left in the atrium. We have a snack room on the second
18 floor at the top of the stairs under the white awning for
19 coffee and snacks. And if there is an emergency and we
20 need to evacuate the building, please follow the staff
21 outside to the park that is kitty corner to the building
22 and wait there until we're told that it's safe to return.

23 Today's workshop is being broadcast through our
24 WebEx Conferencing System and parties need to be aware
25 that you are being recorded. We will make an audio

1 recording available a couple of days after the workshop
2 and a written transcript will be posted on our website in
3 about two weeks.

4 During the public comment period at the end of
5 the workshop today, we'll take comments first from those
6 of you here in the room, followed by those participating
7 via WebEx. When making comments or asking questions,
8 please come up to the center podium and speak into the
9 microphone so that we can make sure that your comments
10 are in the transcript and that the people participating
11 on WebEx can hear you. And it is also helpful if you can
12 give our Court Reporter your business card when you come
13 up to speak, so we can make sure that your name and
14 affiliation are correct.

15 For WebEx participants, you can use either the
16 chat or raised hand functions to let our WebEx
17 Coordinator know that you'd like to make a question or
18 comment, and we'll open your line at the appropriate
19 time.

20 We're also accepting written comments on today's
21 topics until the close of business October 11th, and the
22 Notice for today's workshop, which is available on the
23 table out in the foyer and also on our website explains
24 the process for submitting comments to the IEPR docket.

25 The Energy Commission is required to prepare an

1 Integrated Energy Policy Report every two years that
2 includes assessments of energy supply, demand, price,
3 delivery and distribution. Based on these assessments,
4 the Energy Commission provides recommendations in the
5 IEPR for policy actions to ensure reliable, affordable,
6 and environmentally benign sources of energy for all
7 Californians. Today's workshop is to get public input on
8 the staff's Natural Gas Market Assessment which includes
9 an update of current natural gas trends related to
10 supply, demand, infrastructure, and pricing, as well as
11 input on staff's Reference Case and scenarios that
12 portray possible future estimates of natural gas demand,
13 supply and prices.

14 As part of the 2011 IEPR Proceeding, we have held
15 two previous workshops related to this topic, the first
16 on February 24th, which covered Economic, Demographic, and
17 Energy Price Inputs for the Energy Commission's Forecasts
18 for Electricity, Natural Gas, and Transportation Fuels.
19 The second workshop was a staff workshop on April 19th on
20 the Natural Gas Market Assessment Reference Case, Post-
21 Scenarios, and Safety and Reliability Implications of the
22 San Bruno Incident.

23 The input from today's workshop will be reflected
24 in the Draft 2011 IEPR, a revised schedule of which was
25 posted on our website yesterday. Under the revised

1 schedule, the Draft 2011 is anticipated to be released
2 for public comment on December 1. Unlike past years, we
3 will not be holding a workshop on the Draft IEPR, but
4 instead will be seeking written comments which are due
5 December 22nd. After considering those, the IEPR
6 Committee will revise the report and release the proposed
7 final 2011 IEPR on January 24th for formal adoption at the
8 Commission Business Meeting on February 8th.

9 Because the Final Natural Gas Market Assessment
10 is scheduled to be released in December of 2011, we plan
11 to include a summary of the final results of the
12 assessment in the proposed final 2011 IEPR that will be
13 released in late January.

14 So with that, I will turn it over to the dais for
15 opening remarks.

16 CHAIRMAN WEISENMILLER: Good morning. Welcome to
17 the Energy Commission. Obviously, natural gas is
18 marginal fuel for us on the electricity side, so it sets
19 a key role in our power production and also in our
20 pricing. So we're looking forward to an interesting
21 conversation today; there are obviously a lot of
22 uncertainties and questions that we'd like to understand
23 better.

24 COMMISSIONER DOUGLAS: Good morning. Welcome to
25 the Commission. I'm looking forward to the workshop.

1 Thank you.

2 COMMISSIONER PETERMAN: Good morning. Welcome to
3 the Commission. Glad to be here at this workshop today.
4 I thought this was a very good report that staff has put
5 together and I just wanted to highlight a couple things
6 that are mentioned in the report, but are good things to
7 consider as we move forward and get into the details.

8 First is about forecasts and what the value of
9 them is to us as a Commission and to our various
10 stakeholders. So I would say we don't expect forecasts
11 to be predictive of the future, but we do expect them to
12 inform us about possible futures, and I think the
13 scenarios that staff is presenting do that.
14 Particularly, what I like about what staff has done with
15 this is that they're looking at a range of plausible
16 underlying conditions and that can be useful. We don't
17 want to be in a position of being surprised and, so, as
18 you see with the different scenarios, there are various
19 assumptions that lead to high and low natural gas prices
20 and I think we can see a range of plausible futures in
21 the scenarios that staff has presented.

22 I will say, though, that despite the ability of
23 anyone to accurately predict natural gas prices or gas
24 market outcomes, people like myself and the Chair and
25 Commissioner Douglas still need to make decisions based

1 on some expectation of what those outcomes might be,
2 which is why we put these forecasts together.

3 I encourage, and I believe staff is committed to
4 using these models to develop insights, rather than
5 simply quantitative results, and we can use these
6 insights and our quantitative results to compare to other
7 scenarios that are out there, other results that are out
8 there, and most importantly to evaluate alternative
9 scenarios or a future using different sets of
10 assumptions. I think what staff has done in this regard
11 has been useful and I look forward to hearing your
12 feedback. Thanks a lot.

13 MR. TAVARES: Okay, Commissioners, good morning.
14 Good morning, Advisors. My name is Ruben Tavares and I
15 am part of the staff here at the Energy Commission.

16 During the last three IEPR cycles in 2005, 2007,
17 and 2009, the Commissioners expressed concerns regarding
18 the methodology and the model that staff used to generate
19 natural gas perimeter outputs. The Commissioners
20 recommended to staff, and I quote -- that was in the 2005
21 IEPR -- "to investigate alternative forecasting methods
22 to better assess future gas prices."

23 In the 2007 IEPR Report, the Commission also
24 directed the staff to conduct a rigorous verification of
25 natural gas supply and price. And, finally, in the 2009

1 IEPR, the Commissioners further enforced their previous
2 direction, indicating that the uncertainty associated
3 with predicting major input variables and resulting
4 natural gas price forecasts, questioned the value of
5 producing a day-specific specific single point natural
6 gas price forecast. Again, that was in the 2009 IEPR
7 Report.

8 Given these directions, staff is now proposing a
9 different way to address the Commission's concerns. As
10 indicated by Commissioner Peterman, we do not expect our
11 forecasts to be predictive of the future, but we do
12 expect to be informative about possible future outcomes.

13 The new approach entails developing a Reference
14 Case as a starting point in several possible scenarios.
15 Because of the time it took to review the methods and
16 models, staff did not have adequate time to independently
17 develop and populate a model with data, therefore the
18 staff proposed at the February 24 and April 19 workshops
19 to develop a California natural gas Reference Case based
20 on the Rice University Reference Case. In addition,
21 staff also proposed to simulate six cases besides the
22 Reference Case. This step implies changing assumptions
23 and inputs to the Reference Case to generate different
24 outputs.

25 The scenarios included are high price and low

1 price cases at the national level, a restricted
2 production shale case, California high and California low
3 natural gas demand cases and, finally, a case where the
4 pipeline pressures for the Baja and the Redwood paths
5 will be reduced to observe potential impacts in the
6 market.

7 In order to generate the California Reference
8 Case and the rest of the cases, staff worked very closely
9 with our consultants, Professor Ken Medlock of Rice
10 University, and Katie Elder of Aspen Environmental.

11 Today we have four presentations that will detail
12 the inputs, assumptions, and outputs of the cases we've
13 developed. Dr. Medlock will present the Reference Case.
14 He was initially planning to be here personally with us,
15 but he got ill late yesterday, and could not travel.
16 Nevertheless, he is joining us through the WebEx and he
17 will be presenting his material remotely. He also will
18 be available for questions any time during the workshop.

19 Our second presenter is Leon BRATHWAITE, he is
20 part of the Commission staff and he will address the
21 national high and low price cases, in addition to the
22 shale constraint case. Our third presenter is Ross
23 Miller of the staff and he will be presenting the
24 California focused results from all cases, including the
25 high and the low California gas demand cases. And

1 finally, Katie Elder will describe the pressure reduction
2 case.

3 To help us in the discussion of these cases and
4 other relevant natural gas issues, we invited George
5 Wayne from El Paso Natural Gas. George is the Department
6 Head and Manager of a Strategic Market and Analysis for
7 El Paso Western Pipeline Group, which is a division of El
8 Paso Corporation. He currently oversees the analysis for
9 six of El Paso's interstate gas pipelines, including the
10 Ruby Pipeline. He prepares gas production, demand and
11 price and projections for the western United States,
12 Canada, and Mexico for El Paso.

13 Our other discussant is Lee Bennett, he is the
14 Manager of Pricing and Business Analysis at TransCanada.
15 He has spent 22 years in the natural gas industry and he
16 has held positions with major natural gas pipelines and
17 marketing companies.

18 Scott Wilder is a Business and Economics Advisor
19 at SoCal Gas and has worked with the company since 1993.
20 He specializes in economic forecasting and he has also
21 worked in the past on forecasting electricity demand for
22 PG&E.

23 Mia Vu, she joined PG&E late last year, she is
24 the current Manager of Natural Gas Policy, Planning and
25 Strategy at PG&E. Mia has extensive experience in many

1 facets of the energy industry, including oil, electricity
2 and natural gas.

3 Finally, Amy Mall is joining us on the Web, she
4 is the Senior Policy Analyst for the Natural Resources
5 Defense Council and she focuses on protecting public
6 lands in the west and promoting responsible energy
7 development. She has served as an Advisor to the
8 Director of the White House National Economic Council and
9 has worked for U.S. Senator Dianne Feinstein and former
10 New York Governor Mario Cuomo.

11 Today's workshop focuses on Natural Gas, the
12 results of our modeling efforts. Each and every result
13 is presented to you for comment, and we will be accepting
14 comments on today's topic until the close of business
15 October 11th of this year, 2011. The Notice for today's
16 workshop, which is available on the table in the foyer
17 and is also on our website, explains the process for
18 submitting written comments to the IEPR Docket.

19 Are there any procedural questions before we
20 start? Okay.

21 MR. RHYNE: Good morning. My name is Ivin Rhyne
22 and I manage the Electricity Analysis Office of which the
23 Natural Gas Unit is a part. Before we jump in, I want to
24 emphasize one thing for those who are participating via
25 WebEx and also who are in the room. We have a relatively

1 distinguished panel joining us today and we've broken
2 this workshop up into some logical pieces, intending to
3 spur some discussion with regard to the elements, the
4 results, and what those results infer. However, we don't
5 want to limit ourselves to the questions that are put
6 forward in the agenda, nor do we want to limit the input
7 to simply those who are a part of the panel. And so I
8 want to, before we get started, encourage those who are
9 here, as we go through the day we're going to stop after
10 each of these sections, we think these breaks are logical
11 in the sense that they kind of capture large pieces
12 together; we're going to stop, we're going to ask some
13 questions, we'll ask our panelists some of these
14 questions, but we also want to encourage both questions
15 and answers from those who are in attendance both in
16 person and on the Web. And I think that, if we have that
17 kind of an input, it will make this a much more
18 productive and interesting day for everyone involved.

19 So I just wanted to encourage that before we get
20 started and I'll be back at the end of this to wrap the
21 day up. So, with that, I'll turn it back over to Ruben.

22 MR. TAVARES: Okay, thank you. I think we're
23 going to start with our first presenter and that is Dr.
24 Ken Medlock. Again, he is in Houston, but he's joining
25 us remotely. Ken, are you there?

1 DR. MEDLOCK: I am.

2 MR. TAVARES: Ken, we're going to start with your
3 presentation and just a minute here.

4 DR. MEDLOCK: Okay, I guess I'll just give you
5 direction to change the slides as we go? Is that
6 correct?

7 STAFF: Yes.

8 DR. MEDLOCK: Okay. All right, so I think you
9 got a good sort of recap of all that's sort of gone into
10 what I'm about to talk to you about. There is a lot of
11 detail in here that's been added specifically for the
12 work being done by the California Energy Commission that
13 was not part of the Rice University Original Reference
14 Case and, in particular, that detail focuses on Energy
15 Infrastructure in the Western United States. So I will
16 try to highlight a lot of that as we go through this, but
17 also bearing in mind, I'm going to tell you a little bit
18 about the broader model itself so you can understand the
19 context in which everything sits. Next slide. Again.
20 Next slide, sorry.

21 Basically, what the World Gas Trade Model is, and
22 I'll avoid using the word "Rice" in front of this because
23 I understand what I'm going to present with regard to
24 results is actually the California Energy Commission's
25 Reference Case, it really is a tool that's been developed

1 to examine potential futures, not necessarily predict a
2 specific outcome because there are lots of variables, as
3 we all know, around which there are tremendous amounts of
4 uncertainty from as simple as understanding what economic
5 growth will be over the next five years to understanding
6 what sorts of environmental policies and energy policies
7 might be adopted to influence outcomes in the next decade
8 or so. And whenever you sort of build a model in which
9 you're going to simulate a particular future, you have to
10 take a stand on all these sorts of things, so that's why
11 what you typically try to do is have a tool that's
12 flexible enough to understand sensitivities around that
13 baseline, whatever that happens to be. And what I'm
14 going to present to you today is in terms of the
15 Reference Cases is that baseline, it's by no means meant
16 to represent what I think, you know, if you were to ask
17 any individual member of the staff, or myself, you know,
18 what we actually think the real outcome would be, we
19 might all actually have very different answers, but this
20 is a Reference Case that we sort of agreed on and it's an
21 agreed upon baseline for which we could develop scenarios
22 around.

23 The model is actually very very detailed. There
24 are over 290 different demand regions represented in the
25 model. Globally, there are about half that in terms of

1 the number of supply regions -- I'll get to those in just
2 a minute -- but, on the demand side, there is a
3 difference in the way demand is treated in the United
4 States vs. other places in the world, and that largely
5 owes to data availability, which is, you know, you get
6 outside the U.S. and you run into these -- let's just put
7 it this way, if you're doing data analysis, it's nice to
8 be doing data analysis on the United States because of
9 the manner in which that data is actually disseminated.
10 We can actually estimate demand functions that are much
11 more sort of granular and sector-specific, so what you
12 see here is a quick snapshot of the types of equations
13 that are actually estimated for the commercial,
14 residential, industrial, and power generation sectors.
15 There is a tremendous amount of sub-state detail
16 represented within the model and that's largely to
17 capture the notion that you have to really site sinks, so
18 demand locations appropriate along pipeline networks if
19 you're going to try to simulate flows in any reasonable
20 fashion. And so there's a tremendous amount of care
21 taken in detail sort of in the model with regard to
22 location of demand, as well as what those projections for
23 each individual sector might be.

24 As you can see from these equations, you know,
25 there are a lot of inputs. "Y" would be Gross Domestic

1 Product, so it's an income variable; Heating Degree Days
2 would be "HDD;" Cooling Degree Days would be "CDD;"
3 Population is "POP." So there's a lot of things that you
4 have to assume going forward, these are what we typically
5 call exogenous assumptions. So typically what we do is
6 we assume normal weather, we assume population growth
7 that is in line with United Nations Median Projection
8 Outcome, not only for the U.S., but the rest of the
9 world, and income growth. There is a bit of a recovery
10 in line with some of the work that the International
11 Monetary Fund has done, but long term growth rates are on
12 the order of 2.7 percent. Next slide.

13 For the power generation sector, taking an
14 econometric approach sort of in its purest form is not
15 really adequate because you're talking about something
16 that is very much influenced by policy and so you can
17 have significant structural changes across the board so
18 that you can in effect deviate from historical patterns
19 in a dramatic way, in a short period of time. So what we
20 actually have done is estimated a model that has a fair
21 bit of structure in it. And so what you actually have is
22 natural gas competing against other fossil fuels for a
23 space that is in effect defined by whatever sort of
24 policy driven assumptions, you know, staff wants to make
25 about nuclear power, about renewables, about hydro, so on

1 and so forth. So what that means is, in effect, if there
2 is a Renewable Portfolio Standard that we want to
3 actually target, we can actually make sure that the state
4 hits that target in the specified year and given
5 projections about generation in the power sector, we can
6 once we've taken that projection about RPS on board, we
7 can envision and write a forecast for natural gas demand.
8 Next slide.

9 Outside the United States, as I said, estimating
10 demand is a little bit different, it's done more on a
11 total primary energy basis rather than as distinctly
12 defined by end use sector and, again, that's owing to
13 data availability. Next slide.

14 A lot of what is done, you have to remember,
15 we're talking about long term forecasts, you really have
16 to have a really sort of strong baseline with regard to
17 the manner in which energy demand is influenced by
18 economic growth and overall long term economic activity,
19 and so there is a lot of literature that this model leans
20 on, which is in effect summarized in this slide. Next
21 slide.

22 Understanding what long term growth rates are,
23 though, is difficult at best. And, again, we lean on
24 literature here, economic literature about growth and a
25 phenomenon called "conditional convergence," which is the

1 notion that per capita growth rates will converge to a
2 long run growth rate, acknowledging there can be
3 significant scatter and there can be actually differences
4 in the rate of convergence across countries and across
5 sort of windows of development, and that's really what
6 this is meant to represent. I don't really want to dwell
7 on this too much. If there are questions, we can
8 certainly come back to this. But it is important to
9 understand that, you know, certain countries will by
10 definition from where they sit relative to this sort of a
11 picture, have very high growth rates for a long period of
12 time, China being one. Next slide.

13 And, as a matter of fact, this is a demonstration
14 of that principle. You can see that the long term growth
15 rate for China here through 2030 on average is about 6.5
16 percent GDP -- that's in real terms, not in nominal --
17 per year compared to the U.S. which, in per capita terms,
18 is about 2 percent. So it's very strong and this
19 obviously has implications for global market
20 developments, which eventually matriculate into affecting
21 the U.S. market. Next slide.

22 On the supply side, there is again a tremendous
23 amount of detail, a lot of care taken in trying to
24 distinguish between types of resources, so it's not just
25 identifying a technical type of a resource at a proved

1 reserve, it's actually trying to distinguish the
2 differences between conventional coal, but methane shale
3 and, you know, tide gas as well, and the associated
4 characteristics with the development of all of those.
5 And all that information is actually taken in in terms of
6 the resource sizes and the characterizations to develop
7 cost curves. The basis for a lot of that development --
8 cost curve development -- is the National Petroleum
9 Council Study that was done in 2003, there was tremendous
10 amount of geologic detail that was uncovered in that
11 particular study and a lot of people have criticized the
12 study itself, but it's one of those "don't throw the baby
13 out with the bathwater" kind of things because there's a
14 tremendous amount of very good work that was done there
15 and we've utilized a lot of it to develop these cost
16 curves for regions even outside of North America where
17 you have very little information about the cost of
18 development itself because a lot of that, quite frankly,
19 is proprietary, but you have very good information about
20 geologic characteristics of plays all over the world, and
21 so we utilize that information to generate costs for
22 those regions. Next slide.

23 This is sort of a snapshot. It's kind of
24 difficult to read, but in the upper left is the Former
25 Soviet Union, this is a Production Marginal Cost Curve.

1 Moving across the page, you see the Middle East.
2 Everything sort of on the bottom axis is in trillion
3 cubic feet and, so, really the point about throwing this
4 up here is, if you look below the Former Soviet Union is
5 North America and, yes, there's a lot of shale in the
6 assessment, but when you compare that to assessments for
7 conventional resources in the Former Soviet Union and the
8 Middle East, you realize very quickly that, yes, there's
9 a lot of gas here, but there's a lot of gas there, too.
10 And a lot of it, well, most of it is actually in terms of
11 what has been assessed of the conventional variety, which
12 makes it a little bit lower cost. And that actually has
13 a bearing on the kind of outcomes we see in the model.
14 Next slide.

15 The model actually does make investments, there
16 is no sort of assumption about what the supply curve in
17 any given period looks like, so you will have very
18 different sort of outcomes with regard to what is
19 ultimately proved and produced depending on the kind of
20 scenario you run. Basically what you have to do is load
21 up a cost of supply curve; so, what does it actually cost
22 to develop this resource? And the model will actually
23 look at the rates of return on different types of
24 investments and make the investment that actually makes
25 the producer better off -- best off. And this is all

1 done in the competitive environment, so there is no non-
2 competitive behavior and certainly that is a, you know,
3 in terms of modeling a Reference Case, that is an
4 assumption because obviously when you think of the gas
5 market, you can think about all sorts of instances where
6 non-competitive behavior sort of dominates outcomes,
7 particularly if you go outside of North America. But we
8 try to capture some of that through changing the required
9 rates of return on investment on different types of
10 regions, particularly areas where we see there might be
11 more of this towards -- gas indexation to oil will
12 actually have contract dominated terms on certain sorts
13 of supplies that are for oil index, so there's a lot of
14 thought, if you will, that goes into trying to model
15 those kinds of peculiarities in the market. But in a
16 more fundamental way, when you look at sort of projecting
17 things in the long term, you can't really make
18 assumptions about, well, what will the European gas
19 market look like 30 years from now. Nor can you do the
20 same for the U.S. markets, so we have to sort of let the
21 commercial considerations really drive a lot of the more
22 longer term outcomes, recognizing however, that required
23 rates of return on investment will vary by region and
24 that's largely reflective of risks associated with gas
25 investments, specifically in those regions. Next slide.

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1 This is a sort of a generic representation of
2 what -- it's a sample, if you will -- of the costs that
3 are actually loaded in the model. This is all in real
4 2005 dollars and that's an important sort of thing, it's
5 not actually on this slide, but -- and it does not
6 include investments at the wellhead and sort of gathering
7 up to the liquefaction plant, but this gives you an idea
8 of what's actually in the model. And you can see there's
9 a lot of deviation with regard to sort of regional cost,
10 arctic being the most expensive and you move into
11 Australia and that's actually quite expensive northwest
12 shale, in particular, because a lot of the environmental
13 constraints that are placed on developments there. Next
14 slide.

15 So more on shale. This has sort of been the news
16 of the day, if you will, or of the decade. Next slide.
17 First, and this is for those of you with a geology
18 background, you might recognize this as a modified
19 version of a McKelvey Diagram, it really is just meant to
20 represent what we are trying to capture. The big blue
21 bubble is meant to be resource in place, so that's all
22 gas in place -- it's by no means all going to be
23 ultimately recoverable -- to sort of get an understanding
24 of what is ultimately recoverable, you have to move down
25 to the second largest bubble, which is the Technically

1 Recoverable Resource and, you know, that can change over
2 time. As a matter of fact, what we've seen in the last
3 10 years is a dramatic shift in the size of that
4 particular bubble owing to innovations in the field
5 directly related to shale. Then, a smaller subset of
6 that would be what is Economically Recoverable, and the
7 difference in the size between that Economically
8 Recoverable resource and Technically Recoverable Resource
9 is, you know, a source of a lot of debate, quite frankly,
10 among analysts largely because what is economically
11 recoverable is defined by what is the actual cost of
12 lifting a resource. When you think about Technically
13 Recoverable, it is sort of cost independent, it's just we
14 have the technology, we can get to it regardless of cost,
15 but that Economically Recoverable resource is really what
16 matters, particularly when you think about simulating or
17 projecting outcomes. Next slide.

18 The other thing that is important to understand,
19 and I say this is important because, when you think about
20 projecting things, you have to take a stand on the cost
21 environment and the fact that you're projecting. And to
22 an extent, the model does allow for uplifting cost to the
23 -- and when I say that, I mean, you know, if you actually
24 have an increase in drilling activity, the model does
25 have built into it some cost inflation, but it will not

1 necessarily represent all cost inflation and what I mean
2 by that is it's easily sort of identified in this kind of
3 a picture. You see Real Oil Price and everything is done
4 on an index basis in this chart, that's why there are no
5 units, so they are dimensional and this just makes
6 everything comparable. The Real Oil Price from 1980
7 through 2009 is actually the blue line. The other two
8 lines, the red and the green, are indices of costs
9 associated with oil and gas upstream developments. The
10 Real Well Cost is the red line, that's actually from EIA;
11 the green line is from the KLEMS database, that's
12 actually a database that is FIC code specific from the
13 Bureau of Economic Analysis. And the thing that you
14 should note is that all three lines are moving together.
15 And that's actually a very important point because, when
16 you think about what kind of cost environment you're
17 projecting, if you put yourself back in the sort of mid
18 to late '90s kind of cost environment, you're going to
19 project a lower price world because, by definition,
20 you're building cost curves that are lower. If you put
21 yourself in the 2008 sort of cost environment, you're
22 going to project a higher price world because the
23 marginal cost supply will by definition be higher. So
24 what we've typically tried to do is take the mid trend
25 through a much larger cycle because this data actually

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1 extends -- this is for exposition only -- the data
2 extends back into the '50s, so what you actually see is
3 sort of a mid-trend, if you will. And part of the point
4 here is to recognize that costs will change over time and
5 there will be cycles in the process, and so that can
6 actually move you around any sort of Reference Case
7 outcome that you would try to model. Next slide.

8 So if you just take a step back 10 years, the
9 world was sort of painted as one in which natural gas
10 would be flowing to North America in the form of LNG, and
11 yet a sort of rush to build LNG import terminals; there
12 were at one point 47 different terminals that would
13 receive certification or were in the application process,
14 nobody thought they would all get built. But this
15 picture sort of tells you why we had that view. What you
16 have here is compositive satellite photographs on clear
17 nights around the world. You can see where all the
18 little white dots are that those are where the lights are
19 on, those are demand sinks. So that's where we consume
20 energy, not just natural gas, but energy. You can see
21 the eastern half of the United States, Western Europe,
22 Japan, South Korea, if you could put a time lapse -- and
23 there is some interesting work being done by some
24 researchers at Purdue actually that have done this,
25 putting a time lapse on sort of the brightness of these

1 kinds of pictures over time, and you can actually get a
2 better measure of what economic development is meant for
3 energy demand, and you can see actually India and China
4 in certain areas getting brighter over the last couple of
5 decades.

6 The other thing that is superimposed on this
7 picture are blobs of color and they go from the deep red
8 down to a sort of purplish blue that kind of disappears
9 in the background. Now, the brighter the color, the more
10 intensely endowed the region is with conventional gas
11 resource. And this is the snapshot of the world that
12 most people had when they were thinking about, well, what
13 will the world look like? What will North America be
14 like when you think about natural gas going forward? And
15 so, you know, a lot of development is tied to West
16 Africa, tied to the Middle East, to move gas into the
17 eastern gulf coast. Next slide.

18 There had been a lot of work and understanding
19 what the global shale gas resource was prior to all this,
20 though. As a matter of fact, it doesn't take much effort
21 to find dissertations that were published in the early to
22 mid-1970s, talking about resources in place, or gas in
23 place, gas content of a shale formation. So, to a lot of
24 geologists, shale was a known quantity, it really was
25 just an issue of a technology waiting to happen. And so,

1 to a lot of people who sort of followed this a long time,
2 this really is a technological revolution, it's not as if
3 we've just miraculously found something we didn't know
4 was there. And so that's really what has made this, I
5 think, happen so quickly is once the technological
6 hurdles were crossed, you were able to make a lot of
7 resource that you knew was in place extractable in a very
8 short period of time. Next slide.

9 Some recent updates of the data that Rogner put
10 together back in the late '90s, which is part of a UN
11 Program, actually indicate that the resource could be
12 even larger. As a matter of fact, there was some data
13 work done by Advanced Resources International funded by
14 the Energy Information Administration, I'm sure a lot of
15 you guys have seen the report. Not all of this resource
16 is in the Reference Case Model, and a lot of that is
17 because what we could incorporate largely owes to, you
18 know, there is a time lag in terms of understanding
19 what's in the Technically Recoverable Assessment and then
20 actually building a cost curve associated with that based
21 on the geologic properties of the shales, and so there's
22 nowhere near what you see down there at 6,600 TcF in the
23 model. But there are some shale resources that are
24 located in other parts of the world besides the United
25 States, which do influence the outcome a little bit.

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1 Next slide.

2 And so, as a matter of fact, what shale has done,
3 or technology, I really should say, has done is change
4 the way we sort of view the natural gas world. As a
5 matter of fact, you take that satellite photograph and
6 you superimpose on it where all those shales are, and you
7 see that the location of a lot of this resource is quite
8 strategic, in fact, because you know there's a high
9 coincidence in terms of its location and where the lights
10 are on, and so that actually makes it attractive not only
11 commercially, but from a lot of geopolitical angles, as
12 well. Next slide.

13 Obviously, there has been an evolving state of
14 knowledge in the 2003 study that are referenced before
15 the technically recoverable assessment that the NPC
16 actually adopted, it was only 38 trillion cubic feet for
17 all of North America, so that's obviously a low number.
18 By 2005, some activity had really started to commence or
19 take shape in the Barnett and the Fayetteville, in
20 particular, those two shales and, so, most estimates
21 place that resource in terms of what was Technically
22 Recoverable at around 140 tcfs; as a matter of fact,
23 that's what EIA was using in its work at that point.

24 Then there were several other studies that sort
25 of followed on the heels of that and you can sort of read

1 the numbers yourself, but the point is you can see the
2 number gets bigger every year. And so that's really --
3 that trend really owes itself to a better understanding
4 and delineation of the resource itself. The work that
5 we've actually done at the Baker Institute indicates a
6 technically recoverable resource of about 630 TcF. Next
7 slide.

8 And this sort of lays out exactly how that
9 resource is distributed according to the Reference Case
10 and the breakeven price associated with each one of those
11 resources. Now, the breakeven price is really there
12 meant just to be sort of a reference point, if you will.
13 It is a point on a cost curve and it's meant to represent
14 roughly where you can get to about -- it's not the first
15 entry point, it's about 50 percent of the resource and
16 the slope of the curve, so in some ways the breakeven
17 prices listed here might be a little misleading, will
18 vary by shale. So you have some relatively low cost
19 resources that are ultimately what is targeted first, but
20 then, as you moved through time, you have to target
21 higher and higher cost resources. So that's where you
22 see in some of the larger shale plays the tiering that's
23 done, so on and so forth. Next slide.

24 There is a lot of uncertainty not only inside
25 North America, but outside North America, probably

1 increases by an order of magnitude with regard to what
2 the actual cost of development will ultimately be. One
3 of the biggest issues with shale developments sort of
4 outside of North America is actually market structure.
5 It's a fact that it's often under-appreciated, but a lot
6 of what we've seen in the United States owes itself
7 directly to market structure, so you know, the fact that
8 you have unbundled capacity rights, transportation --
9 transportation services are unbundled from ownership of
10 the facility -- that actually helps because it basically
11 means anybody can bid for the right to move gas. If you
12 think about most places, with the exception of Australia
13 outside of North America, that's not the case, you
14 typically have a large compass that can block access by
15 any sort of small developer, so that's a pretty important
16 facet to sort of take on board when you think about
17 what's actually happening in the United States.

18 Another thing is the manner in which property
19 rights are actually allocated and accessed. You know, in
20 the United States a lot of development owes to developers
21 being able to directly negotiate with landowners, whereas
22 if you go outside of North America, that's generally not
23 the case either. Next slide.

24 And so what you actually see in the model, just
25 so you understand what's in there, there is about 800 TcF

1 outside of the United States. A good chunk of it is in
2 Canada and Mexico. A lot of the Mexican shale is
3 relatively high cost and that is largely because what
4 you're talking about, particularly when you think about
5 the Burgos and Sabinas Basins, are shales that are
6 extensions effectively of the Eagleford shale which is in
7 South Texas. The trouble, though, there -- a lot of
8 people have probably heard about the massive amount of
9 growth that is occurring there and a lot of that owes to
10 the NGLs that are associated, the liquids that are
11 associated with development. As you move farther and
12 farther south, you get into drier parts of the fairway,
13 so you're talking about a higher cost in effect on a per
14 unit basis of production because you don't get that
15 liquids uplift, and so that's actually another important
16 point there. We actually have a well economics model
17 that is used to develop these cost curves and there are
18 liquids credits applied when there is a liquid content
19 associated with the gas stream. Next slide.

20 And again, this is sort of a rehash of some of
21 the other things, but there are multiple issues that face
22 shale development, so when we think about generating a
23 Reference Case projection, it's important to understand
24 that there are some things that are global and some which
25 are actually regional and specific to the United States,

1 in particular, that could alter the course. And so
2 understanding the simple fact that a lot of that is
3 policy related is important, particularly if you want to
4 understand what any given sort of simulation might
5 actually mean, and understanding its likelihood of
6 occurring. Next slide.

7 And so now we can sort of dive into some results.
8 Before I do this, are there any questions? Does anybody
9 have any questions just about the model itself?

10 COMMISSIONER PETERMAN: Hi, Dr. Medlock. This is
11 Commissioner Peterman. How are you?

12 DR. MEDLOCK: Hi. How are you doing?

13 COMMISSIONER PETERMAN: Good, thanks. I did have
14 one question about your assumptions around RPSs for the
15 different states. What is the rationale for assuming
16 that states meet their RPSs five years later in the base
17 case?

18 DR. MEDLOCK: Okay. The base case -- there were
19 a couple of reasons. We went through a pretty massive
20 recession and, by some accounts, we still are in the
21 middle of it, but what that did is it actually put some
22 stress on state budgets, it put some stress on -- and,
23 you know, by association it put some stress on the
24 ability to actually meet some of these projections
25 because what you end up doing is particularly in places

1 where some of the RPS push is supported through State
2 budgets, or State Government budgets. It was more, you
3 know, we look out, we see what did the recession do,
4 maybe it delayed economic development by five years. And
5 so you sort of shift the budgetary constraint by five
6 years and that's effectively what happened. In our own
7 work here at the Baker Institute, we would actually have
8 that five years applied to California, as well, but given
9 the impetus at the CEC, we actually went ahead and had
10 California meet its stated goal in the Reference Case.
11 And, you know, we actually in looking at this, a lot of
12 this work is done in the spreadsheet that is sort of
13 modeled so you can develop a reference input for the
14 model. You can see that, in certain states, you know,
15 trying to force that to occur, particularly states where
16 you have relatively low gas consumption to begin with,
17 you're basically squeezing gas almost completely out of
18 the picture, and so, by a lot of accounts, that's just
19 not a very realistic outcome. So there is some modeler
20 judgment sort of overlaid there.

21 COMMISSIONER PETERMAN: Great, thanks. That
22 helps.

23 DR. MEDLOCK: Sure. So when you look at the
24 Reference Case, this is really just meant to demonstrate
25 what the composition of U.S. production is from 2010

1 through 2040, you see that shale gas production does grow
2 in the Reference Case to be in excess of 50 percent by
3 roughly the early to mid-2030's -- actually, in this case
4 it is by 2030 at 50 percent, but the point is that
5 resource assessments that we just went through is really
6 what is driving this particular outcome.

7 The Canadian shale is not pictured here, but
8 there is fairly strong growth from the Western Canadian
9 shales, in particular. It reaches about a third of total
10 output in the 2030's. Now, one of the things that is
11 also happening in Canada is you've got strong declines in
12 the conventional resources, and so largely what that is
13 doing is just offsetting the decline, allowing for some
14 very modest growth, some of which is soaked up in oil
15 sands developments. Next slide.

16 And so, to actually understand clearly what's
17 happening with shale by basin or by play in all of North
18 America, that's what this slide gives you. Everything
19 below that dark red is the United States. If you go from
20 the red to the orange, sort of deep red, that's Canadian
21 shale, and then sort of farther north of that is where
22 Mexico begins to sort of enter the fray in the late
23 2020's. What you can see from this slide is there are
24 some very high growth regions, mainly the Marcellus,
25 which is that big wedge at the bottom and actually I was

1 just looking at some data the other day and it turns out
2 this prediction for the Marcellus is actually an under-
3 prediction of where it actually is now, so that -- kind
4 of throw some water on that particular graphic, but
5 there's actually a very important point that I wanted to
6 make on this, it's that developers, as they move into
7 these shales, are learning a tremendous amount about the
8 resource itself and about the geology itself, and a
9 really good case in point, if you look at the Barnett
10 shale and you can actually access well filed data
11 through the HPDI database for the Barnett, you can
12 actually see bottom hole locations vs. where the pad site
13 is and understand how developers have been moving through
14 that shale, and there have been over 14,000 wells drilled
15 in the Barnett, so that it's a very rich data source to
16 sort of understand how developers will move through
17 shales and learn as they go. What you can actually see
18 is from an existing pad site very early in the
19 development of the Barnett, it almost looks like a spider
20 web, so developers were sort of shooting laterals in
21 multiple directions trying to figure out the optimal sort
22 of way to drill up that particular play, and then you
23 will see sort of, if you put a time lapse on that, you
24 move away from the spider web maybe 40 to 80 acres and
25 you start to see the same developer laying what almost

1 look like railroad tracks if you're looking at a topology
2 of the resource. So what that is telling you is that
3 they're figuring out the best way to attack the shale and
4 it's very evident in the Barnett because what you've
5 actually seen in the last three years is a pretty
6 dramatic decline of rig counts, but the production is
7 held stable. And what that is telling you is they are
8 actually able to target the most high valued portions of
9 the play in a very sort of cost-effective way. And
10 arguably, some of that is actually going on in the
11 Marcellus and the Haynesville, as well, and will probably
12 likely continue. Next slide.

13 In terms of U.S. LNG Imports, the Reference Case
14 basically sees almost no growth until you get well out
15 into the time horizon. And again, this largely owes to
16 what is going on with domestic gas production. Next
17 slide.

18 In terms of U.S. demand, this actually gives you
19 a little bit of history too, but the projection you
20 actually see pretty strong demand growth. We do actually
21 hit the 30 TcF point in the mid to late 2030's, which was
22 sort of the point that everybody had their eye on back in
23 the early '90s, albeit, I guess, based on a lot of the
24 projections that were done then were probably about two
25 decades off, but that's okay. A lot of this growth is

1 really driven by the power generation sector, and so what
2 you actually see, given even with all the RPS
3 requirements, is very strong growth in power generation,
4 particularly as it squeezes on the coal generation fleet.
5 Next slide.

6 For California, you see not much demand growth
7 over the next decade and a lot of that is quite frankly
8 driven by the fact that, in the power gen sector, there's
9 a bit of a squeeze on gas largely because of the RPS
10 Standards. As you move farther and farther beyond that,
11 though, there's a bit of relaxation in terms of the
12 model's functions with regard to the rate at which
13 renewables will grow, and so you do see some gas
14 penetration longer term in the power sector, but it's
15 nothing near as dramatic as what you see elsewhere in the
16 United States. Next slide.

17 In terms of what's happening to price, a lot of
18 what you see in the trends with regard to price and basis
19 are directly related to what's happening on the domestic
20 gas production scene. Looking at basis, you actually see
21 longer term weakening at AECO and that again is directly
22 related to the fact that there are shale resources coming
23 on line there and it's stressing a little bit on the
24 infrastructure. Then, when you move sort of to the top
25 of this basis graphic, you're sort of thinking about

1 points that are farther east, and you actually do see
2 some long term weakening there, largely because of
3 developments in the Marcellus and what it does to those
4 market areas. And the strengthening you actually see at
5 the SoCal border is not necessarily related to demand
6 growth in California, it's actually related to what's
7 happening to prices farther east. All the production
8 growth that is occurring in the Gulf Coast Region and in
9 the Mid-Atlantic shales, for example, is really keeping
10 prices from elevating as much as they would otherwise,
11 and that actually, you know, by direct relation, is
12 having a modest impact on what's happening at the SoCal
13 border. The other thing, of course, that is happening is
14 you do have some demand growth and so it's not really
15 strong enough to signal massive increases in
16 transportation capacity, and so you do utilize capacity
17 that exists a little bit more heavily.

18 You also see, and it's not in this slide, some
19 strengthening of the basis in the Rocky Mountain region,
20 which is also directly related to the production trends
21 in North America, in general. Next slide.

22 Okay, so outside of North America -- before we
23 fully dive into this, are there any questions just in
24 general about what I've shown so far? Obviously there is
25 going to be a lot of detail presented with regard to

1 North America during the rest of this workshop, but if
2 there's anything I've got to address right now? Okay, I
3 guess we'll go ahead and keep moving.

4 Understanding what is actually happening to the
5 global gas market is important because it helps you to
6 understand a little bit what's going on with prices in
7 North America, as well. The U.S., and again, this is
8 very different than the picture most people had 10 years
9 ago, is among the sort of end-using sort of markets, the
10 lowest priced market, so when you compare the U.S. price
11 to European price and to the Asian price, you actually
12 see that the prices in the U.S. are \$1.00 to \$1.50 lower
13 long term. And there is a bit of an uptake in price -- I
14 did notice some of the questions that were submitted
15 prior to the workshop -- in the near term, and a lot of
16 that is related to stuff that is happening outside of the
17 U.S., as well as some stuff that's happening inside the
18 U.S., so there are a couple things going on here, 1) you
19 do see some stronger demand pull from what actually
20 happened at Fukushima, you also see some stronger demand
21 pull due to an economic recovery that is assumed to occur
22 globally over that window in time. And the reason you
23 see that sort of down dip, if you will, in the 2014-2015
24 time frame is directly related to some fairly large
25 contract and supplies coming on line in the Northwest

1 shelf, in particular in Australia, which tend to sort of
2 reverse the increase, if you will, that you see in that
3 first couple of years. So what that tells you is that
4 there are some things that are sort of hard wired, if you
5 will, that could cause some decent up and down, if you
6 will, in terms of average annual prices over the next
7 couple of years. Next slide.

8 With regard to composition of production in
9 Europe, you see some shale coming on in Europe, it
10 doesn't really happen nearly as fast as what we've seen
11 in the United States. Just for those of you who are
12 following this, there is no shale production in France.
13 The ban on hydraulic fracturing is honored in the
14 Reference Case, and so none of that is actually available
15 as an identified resource in France. Next slide.

16 Russia really sees its market share affected
17 pretty dramatically by a lot of what's going on, so we
18 actually just completed a study at the Baker Institute
19 for the Department of Energy looking at what shale is
20 meaning on a geopolitical scale, or what it could mean on
21 a geopolitical scale, and one of the things you actually
22 see is that, if shale developments were to continue sort
23 of as modeled in a Reference Case, Russian market share,
24 although the volumes don't fall that dramatically, market
25 share in Europe actually does fall. It's obviously going

1 to grow in Northeast Asia, but that's because they really
2 don't have much of a footprint there now, but if you were
3 to compare this to a case in which you don't have shale
4 developments, you see a quite dramatic difference. Next
5 slide.

6 In terms of what's happening in China, there is
7 also some shale gas production and growth there. You can
8 see that in this particular slide in the upper right,
9 it's the orange bit. China really is the driver of the
10 boat in terms of LNG market development because of the
11 tremendous demand growth that occurs there. But you can
12 see that that demand growth is not only by pipeline in
13 LNG, but also by domestic production increases. China
14 actually faces a little bit different, I think, picture
15 than a lot of places when you think about not only a lack
16 of infrastructure to move the gas, but lack of suitable
17 sources of water. There's a lot of areas, and you can
18 see this in that bottom left graphic, where there are
19 shale resources identified, so those are the light green,
20 but those resources, with the exception of the Ordos and
21 Songliao Basins, are highly coincident with areas of high
22 water stress, and so it's going to be interesting to sort
23 of watch what happens in China, what sort of new
24 technologies might come along to sort of help the Chinese
25 endeavor to increase shale production. One of those is

1 actually sourcing deep source -- deep aquifers, which is
2 a sort of briny source of water that is typically not
3 tapped for human consumption, and to the extent that that
4 actually occurs, there are a couple of companies that are
5 actually testing that right now. Drilling those wells
6 actually allows for not only a source of water that
7 wouldn't compete with human consumption, but it allows
8 you to access an aquifer source that you can re-inject
9 into, and you're talking about very very deep briny water
10 that is typically, again, not accessed for human
11 consumption. So, obviously all of this raises the cost
12 of development, so exactly how far that goes and whether
13 or not it proves to be successful is still sort of on the
14 table. Next slide.

15 Where is LNG going? Well, the U.S. is the tiny
16 thin bit at the very top, it doesn't really look like
17 much, so in terms of U.S. sort of footprint in the global
18 gas market, it's not very large. Most of the action is
19 occurring in Asia, so basically from the bottom of the
20 graph up to that sort of deep sort of reddish brown,
21 which is South Korea, that's all Asia. So Asian
22 customers are really what drive -- growth in Asian demand
23 is really what drives a lot of the developments in the
24 global gas picture. Next slide.

25 Where is it coming from? Well, in the Reference

1 Case, Iran is actually allowed to develop later in the
2 time horizon, Venezuela is allowed to develop later in
3 the time horizon, and so you see a pretty diverse source
4 of supply through the mid-2020's to 2030, about half of
5 LNG exports -- well, not quite half, about 35-40 percent
6 of LNG exports -- are coming largely from two countries,
7 and that's Qatar and Australia. But you do see some
8 emergence from some of those other marginal sources like
9 Iran and Venezuela when demand growth continues sort of
10 through the 2030's. And obviously that result can be
11 challenged base on current geopolitical trends, but again
12 you're talking about 20 years into the future, so some of
13 those constraints are relaxed in the Reference Case.
14 Next slide.

15 I guess that's it, actually. There are some
16 Appendix slides which are in here really just to support
17 conversation around the kind of assumptions regarding
18 international pricing schemes, so on and so forth, which
19 I'm happy to entertain. There is also some discussion
20 about the feasibility of U.S. LNG exports.

21 What I've done in this particular slide is just
22 take those marginal costs of supply curves that I showed
23 you earlier and put them on the same picture. And one of
24 the things that is important to understand and is tied
25 directly to some research that is apparently involved is

1 the role of the U.S. Dollar and understanding what that
2 actually means for relative costs around the world.
3 One of the things that is certainly true right now in an
4 environment where the U.S. Dollar is about as weak as
5 it's been in the last 40 years is that tends to make the
6 U.S. look like a low-cost region, and this is actually
7 fueling a lot of what you see with regard to the
8 feasibility of LNG exports in the United States. In
9 particular, you think about natural gas markets outside
10 of North America. Let's say I'm in the U.K., for
11 example, gas there is not traded in dollars per mMVt or
12 dollars per Mcf, and it's actually traded in pence per
13 therm. So when you want to convert that back to a U.S.
14 Dollar denominated sort of metric, you have to apply an
15 exchange rate, and so the exchange rate by definition has
16 a pretty strong role in understanding what happens to
17 spreads, not only between oil and gas, oil which is a
18 fully fungible internationally traded commodity, U.S. gas
19 is not, but also between regional gas prices. And so, in
20 the Reference Case, you don't really see much in the way
21 of LNG exports from North America, but that's because the
22 Reference Case is pinning itself to a sort of 2005 kind
23 of world. And what that means in effect is that the U.S.
24 Dollar is in a much stronger position relative to where
25 it is today.

1 If you run cases, and we've done this, we have
2 not done it for the CEC work, where you impose more
3 constraints and you change the value of the dollar
4 relative to international denominations, you do see some
5 modest growth in exports, but that's largely from Canada,
6 not necessarily the Gulf Coast in the United States. So
7 what this graphic, this particular table actually shows
8 you is that, given the current value of the U.S. Dollar
9 relative to major currencies, and the average is where
10 it's been over the last 30 years, the high is the high
11 over the last 30 years, the low is the low previous to
12 where we are today, and I should actually clarify that -
13 high and low are not actually the highest point and the
14 lowest point, they're actually a peak to the P90 in the
15 distribution of value to the U.S. Dollar against all
16 major currencies. But you can see if you just take an
17 oil price, say \$96.15, which is where it was about two
18 months ago, actually, the actual Henry Hub price, given
19 those particular environments, associated with this work
20 that I've been involved in, is depicted in the red and,
21 so, what you actually see is that an average, if we're in
22 a \$96.00 world, the price of gas in terms of the low, the
23 price of gas would be close to \$8.00, which is closer to
24 that sort of 12:1 kind of ratio that a lot of people used
25 to talk about. The thing that sort of gets lost in the

1 conversation that is the point of this slide is the value
2 of the U.S. Dollar in that conversation. There's a fair
3 amount of stability in terms of where the dollar is set
4 vs. other major currencies prior to the last five years
5 for the preceding 20. The last time we saw a gas oil
6 window that is as big as it is today was in the late '70s
7 and, coincidentally, that's the last time we saw the U.S.
8 Dollar as weak as it is today. So it's a very important
9 thing to sort of take on board when you're thinking about
10 these sorts of issues. And it's obviously another sort
11 of thing to take on board when you're thinking about the
12 relevance of this particular Reference Case vs. what
13 could potentially occur over the next 20-30 years.

14 I think this is probably a good place to stop and
15 sort of address questions if there are any about the
16 Reference Case.

17 MR. WAYNE: Doctor, I was wondering what your
18 assumptions are --

19 COMMISSIONER PETERMAN: Wait, could you state
20 your name? Sorry.

21 DR. MEDLOCK: There were scenarios designed
22 specifically to address energy, not only in the United
23 States, but California and sort of how policies might
24 sort of unfold to effect outcomes not only in the United
25 States, but also in California, and that's going to be, I

1 think, the emphasis of the remaining presentations.
2 Designing those scenarios was interesting and there was a
3 lot of work that actually went into it. I'm looking
4 forward to actually seeing those presentations as the day
5 progresses, and I'll be hanging on the line to answer any
6 questions that might come up, that if I can address I
7 certainly will.

8 MR. WAYNE: Hi. This is George Wayne with the
9 Western Pipeline Group of El Paso. I have a few
10 questions regarding your Reference Case, one specifically
11 because it's been out there for a long time, it seems to
12 be about 10 years away in everybody's forecast, it has to
13 do with Arctic gas and McKinsey Delta gas, you didn't
14 really discuss that, and how that impacts your
15 assumptions where you have it coming in, if not. And
16 also, across our borders, the trade in balance that we
17 see occurring between less imports from Canada, more
18 exports to Mexico, that growing trade in balance, and how
19 do you weave that into your Reference Case?

20 DR. MEDLOCK: Hello?

21 MR. TAVARES: Yeah, Ken, did you hear the
22 questions? Ken?

23 COMMISSIONER PETERMAN: Well, could you repeat
24 your question again just for - because I've almost
25 forgotten what the --

1 MR. WAYNE: Is Dr. Medlock there?

2 MR. TAVARES: Ken, are you there? Can you hear
3 us?

4 DR. MEDLOCK: [No response]

5 MR. WAYNE: Well, I'll repeat my question for
6 everybody else. It has to do with, again, Arctic gas and
7 McKinsey Delta gas coming down from Alaska, you know,
8 that was always a big assumption in most people's
9 forecast, when that was potentially going to hit the
10 United States. I was just wondering where do we weave
11 that into the Reference Case, that particular impact.
12 And then, something that is growing is the trade in
13 balance across our borders, that we see less imports from
14 Canada because we see Canadian decline in imports, that
15 is, and we see more exports to Mexico, again, creating a
16 trade in balance where, well, shale gas production
17 probably absorbed that, but my question is where does
18 that weave into the Reference Case?

19 MS. KOROSSEC: We're having difficulty with Ken's
20 mic is off, so we're trying to email him quickly to see
21 if he accidentally hung up the phone, so...

22 COMMISSIONER PETERMAN: Does staff have any
23 insight into the questions raised by Mr. Wayne?

24 MR. TAVARES: I think we want to hold on for a
25 little bit, they are trying to solve those technical

1 issues. But there are some other questions online by
2 now.

3 MS. MALL: Can you hear me?

4 DR. MEDLOCK: I can now, there we go.

5 MR. TAVARES: Oh, okay.

6 MS. MALL: Yeah, I could hear you before, but I
7 was muted, and then I just got something that said "you
8 have been unmuted" by the host.

9 DR. MEDLOCK: Oh, okay. I actually just got your
10 chat and it said -- okay, wait a minute, I'm actually
11 sending the thing to Donna.

12 MS. MALL: Okay, good. I was trying to get
13 anybody's attention.

14 DR. MEDLOCK: Yeah, I think you and I are the
15 only two that can talk to each other right now.

16 MS. KOROSK: Well, we can all hear you, though.

17 DR. MEDLOCK: I just sent her a note. She asked
18 if my personal phone was muted. It looks like George
19 Wayne was asking a question.

20 MR. TAVARES: Yes. Ken, can you hear me?

21 MS. MALL: Well, I haven't heard anything except
22 you.

23 DR. MEDLOCK: Okay.

24 MS. MALL: I guess it's worth waiting a little
25 while.

1 DR. MEDLOCK: They can hear our conversation. We
2 cannot hear you guys, so I don't know what's going on.

3 COMMISSIONER PETERMAN: Your question has brought
4 down our system, George, thank you.

5 MS. KOROSEC: We're getting our IT folks here, so
6 I'm not sure what to suggest in terms of continuing the
7 conversation. Maybe we can try to focus on questions
8 from inside the room of staff until we can get Mr.
9 Medlock to hear us.

10 DR. MEDLOCK: I'm actually chatting with Donna
11 right now, so...

12 MS. MALL: Okay, I'll just go on hold and wait to
13 see what you can find out.

14 DR. MEDLOCK: Okay.

15 MR. WAYNE: Actually, it wasn't as bad as my -- I
16 was in Wyoming Gas a few weeks ago presenting and a dog
17 came into the conference and knocked the mic and --

18 DR. MEDLOCK: It looks as if -- I'm assuming you
19 guys can hear me -- it looks as if the podium and the
20 list of participants for me is muted, so that would mean
21 you guys could not communicate with me. So you might try
22 to unmute that.

23 MS. KOROSEC: All right, we found it.

24 DR. MEDLOCK: There it is. There we go.

25 COMMISSIONER PETERMAN: Welcome back.

1 MR. TAVARES: Okay, Ken. I think George had a
2 couple questions for you.

3 DR. MEDLOCK: Yeah, no problem.

4 MR. TAVARES: Okay, go ahead, George and start
5 the questions again.

6 MR. WAYNE: Yes. This is George Wayne with
7 Western Pipeline Group of El Paso. My questions stem
8 from a couple things, one has to do with that we see
9 Canadian exports declining, we see obviously the kind of
10 conventional, but probably more importantly, it has to do
11 with your assumptions of Arctic gas and McKinsey Delta
12 gas, where you weave that into your forecast. And then
13 the last question is sort of in a similar vein, we see,
14 at least at El Paso, growing trade in balance across our
15 borders, less imports from Canada and more exports to
16 Mexico, and again shale gas and other development
17 obviously absorbing that, but just where do you weave
18 that into your Reference Case?

19 DR. MEDLOCK: Okay. Good questions. Well, in
20 the Reference Case, those developments are not assumed to
21 occur at any particular point in time; rather, the model
22 is actually looking at those opportunities in assessing
23 whether or not they will occur. With regard to the
24 McKinsey Delta opportunity, that actually does not occur.
25 The first time it is allowed to happen in the model, so

1 when the investment logic is basically evaluating that
2 particular opportunity, is in roughly 2014 and given what
3 is actually happening in the Lower 48 in the Canadian gas
4 market, more specifically, McKinsey Delta gas is not ever
5 actually shipped south. The more general question in
6 regard to Arctic gas development, so Alaskan gas is
7 eventually developed if done so as an LNG export, though,
8 beginning in about 2038. So basically what is happening
9 is gas production and gas demand in the Lower 48 are more
10 or less in balance and there's very little room to
11 develop that resource and ship it south, so effectively
12 that's what is going on.

13 With regard to your comment about the Canadian
14 gas exports to the United States and U.S. exports to
15 Mexico, you're actually spot on with regard to what's
16 happening in the model. You do see an increased flow
17 south, figure from Texas and to the Mexican market, and
18 you do see a decrease in Canadian exports to the U.S.

19 MR. WAYNE: Thank you.

20 DR. MEDLOCK: Sure.

21 MS. VU: I have a question. This is Mia Vu from
22 PG&E. What is your assumption in the model about the
23 long term relationship between oil and gas? That's the
24 first question. And the second is about industrial
25 demand. My observation is that with the availability of

1 gas and low gas price in the United States, it seems to
2 stimulate the petrochemical sector in terms of using gas
3 as a feedstock. We saw some announcement about opening
4 up the old ethylene plants in the Gulf Coast, as well as
5 some new plants are proposed in the Northeast. And it is
6 a first time, not first time, but for a long time, that
7 the U.S. has more of a competitive advantage in the gas
8 side in the past; the fertilizer and all the industries
9 are moving offshore. And also, when you have the gas
10 available in the major consuming region like the Middle
11 Atlantic, you save a lot of transportation costs on the
12 gas side, as well as on the product side, so do you
13 incorporate that in the industrial demand?

14 DR. MEDLOCK: Absolutely. You do see some modest
15 growth in industrial demand, which is certainly different
16 than if we were to talk about industrial demand trends
17 five years ago, we would have sort of envisioned things,
18 but, yes, there is actually some recovery. We don't
19 necessarily get back to the same levels we saw in the
20 mid-'90s, which is I guess where industrial demand was at
21 its peak before it began, again, that's sort of seemingly
22 at that point a natural decline. But a lot of that owes
23 directly to the fact that you do see softer gas prices in
24 North America, so there is some demand growth in the
25 industrial sector. And with regard to the questions, you

1 know, centering on transportation costs, yes, you do see
2 some growth industrial demand in the Mid-Atlantic region
3 largely because there is a softening of basis there
4 relative to Henry Hub, and that's actually something I
5 showed in the slide earlier. So, absolutely, I mean, the
6 trends in production and the Reference Case directly
7 impact demand response, that's what gives you sort of
8 that demand growth longer term when you look in the
9 industrial sector in the Reference Case.

10 MS. VU: How about the oil and gas --

11 DR. MEDLOCK: Oh, the oil and gas ratio, yes,
12 sorry about that. Well, there is an oil price assumption
13 in the model, and one of you guys from CEC is going to
14 have to help me, what did we assume with regard to oil
15 price projection? I want to say we assumed we were in
16 the mid-'90s in the Reference Case here, which means that
17 you see some price recovery with regard to Henry Hub,
18 sort of up into the mid-6's, so certainly not where --
19 we're not in the 12:1 ratio, but we're certainly inside
20 of the 15:1 ratio long term.

21 MS. VU: Thank you.

22 DR. MEDLOCK: Sure.

23 MR. TAVARES: Any questions? Commissioners, any
24 questions? Okay, Amy, do you have a question for Ken?

25 MS. MALL: No, I had just flagged before to try

1 to get his attention when we were having the audio
2 problem, I'm sorry.

3 MR. TAVARES: Oh, okay. Ivin?

4 MR. RHYNE: Yeah, so we mentioned that we have
5 these kind of discussion driver questions, these key
6 questions here, and I'm going to go backwards a little
7 bit in the presentation to -- there we go -- so this is
8 the reference price case, you see slide 34, you see the
9 prices in 2010 dollars, U.S., Europe, and Asia, you have
10 the peak, and then it kind of levels off there. Ken has
11 talked about the drivers that go into that case. What
12 we're interested now in, both from our panelists and from
13 those who are on the line, as they look at this and they
14 understand the drivers that are involved, what insights
15 or, if I was going to speak more colloquially, kind of
16 what is the story that our panelists kind of see in this
17 draft? And what does that tell us in terms of
18 understanding that this is kind of a business as usual
19 kind of scenario? So I'm curious what our panelists see
20 here.

21 MR. WILDER: Well, Scott Wilder from SoCalGas and
22 an observation also. A question for you, Dr. Medlock. I
23 believe it's in 2015 that the Panama Canal expansion is
24 due to be completed and that's going to permit LNG cargo
25 ships to go through the canal where, at this point right

1 now, it's really prohibitive for them to go around the
2 Cape Horn at the bottom of South America, and there seems
3 to be a real opportunity for U.S. Gulf of Mexico gas in
4 that case to be shipped a lot more economically eastward
5 to China and other East Asian countries, and I wanted to
6 ask if you had any assumptions about that in the model
7 and the results.

8 DR. MEDLOCK: Yes. The Panama Canal option is in
9 the Reference Case. It again, though, is, you know, as I
10 mentioned before, we don't see in the Reference Case any
11 exports from the Gulf Coast, and that's why I actually
12 raise the issue about the value of the U.S. Dollar and
13 the fact that a lot of the stuff in the Reference Case
14 stays on sort of 2005 kind of metrics, so that's
15 certainly something that could be changed if the U.S.
16 Dollar remained very weak, but quite frankly what happens
17 is you don't see that option being utilized on an average
18 annual basis to any extent, and a lot of that owes to a
19 point that I made about new supplies from Australia.
20 There are a couple of big projects that will begin
21 shipments in the '14, '15, '16 time frame, and if you're
22 going to compete with those contracted supplies from the
23 Gulf Coast, you would have to have a pretty ironclad
24 contract with the Chinese or Japanese or Korean customer
25 out of a Gulf Coast terminal or you're just simply going

1 to have to wait for some idle capacity. And given the
2 pace at which supplies are scheduled to come on, that
3 doesn't look like a bet that is going to bear much in
4 terms of fruition, in terms of delivery across the
5 Pacific from the Atlantic via the Panama Canal option, so
6 it would have to be a contracted flow and, quite frankly,
7 right now there are no contracted flows, so there aren't
8 any assumed in the Reference Case.

9 MS. VU: This is Mia Vu again. On the question
10 on the price of the Reference Case, what I observed is,
11 after that blip going up and down, for the long term,
12 what we see here in the forecast is between five and six
13 dollars.

14 DR. MEDLOCK: Yes.

15 MS. VU: And even when we go to the national
16 cases, the variation is about that five to six dollars,
17 so my observation is, when I look at the EIA long term
18 forecast, and other forecasts in the industry, the range
19 are larger. We saw the range between four and eight
20 dollars, so it's a wider range. So that is my
21 observation.

22 DR. MEDLOCK: I can't really speak much to that,
23 I'd have to actually look at the specific drivers and the
24 range of cases that you're actually evaluating. The
25 cases that were constructed, and I'm sure this will come

1 up again and again through the course of the day as those
2 cases are presented, were constructed to try to stimulate
3 some variation in the pricing outcome. One of the things
4 you have to remember, though, is that when you're looking
5 at cases that don't do a lot to deviate the cost of shale
6 gas development, or the availability of shale gas
7 development, is you're not going to see a tremendous
8 variation in the pricing outcome simply because what
9 you're talking about is a very sort of long flat supply
10 curve, in effect. And so that's really sort of what
11 mutes the impacts if you try to derive the deviation and
12 the outcome on the demand side. So what you really have
13 to do to get a significant shift in price is do something
14 to the supply side.

15 MS. VU: Yes. I observed your cost curve is
16 relatively flat between zero to 600 TcF of cumulative
17 production, so that's one of the drivers, how it
18 happened.

19 DR. MEDLOCK: Absolutely.

20 COMMISSIONER PETERMAN: Can I just interject here
21 for a second? This is Commissioner Peterman. Ms. Vu,
22 thank you for asking that question because it's a
23 question I have for staff generally with looking at the
24 low and high price cases, that you do see the range
25 within five to six. And Dr. Medlock, thank you for that

1 explanation, you had Katie Elder here nodding in
2 agreement. But I would just ask staff when we do the
3 final report on this just to highlight that there is this
4 difference with the EIA, and if that is one of the
5 driving reasons, just to point that out because I think
6 it would be useful for all of us. Thanks.

7 Whoever wants to go next with a question - do you
8 have another question, Ms. Vu?

9 MR. RHYNE: And were there any other comments
10 regarding the Reference Case, just general insights from
11 either anyone here in the room or online?

12 MR. WAYNE: I had one question, one granular
13 question that would have to do with California
14 production. I was looking at the Reference Case
15 production and it looked like on the back end of the
16 forecast in 2030 or so, I saw California production
17 increasing and I was wondering what was driving that.

18 DR. MEDLOCK: Price environment, that's largely
19 what it is. So there are resources in California that,
20 you know, on their own merit, in terms of competing with
21 resources out of the Rockies and other resources that
22 will be imported, Canadian supplies, in particular, you
23 know, are sort of lower in the pecking order in terms of
24 their commercial liability, but once the price
25 environment begins to sort of exceed that sort of \$6.00

1 mark, those resources become competitive, and so that's
2 basically what's happening there.

3 MR. WAYNE: Well, then -- again, this is George
4 Wayne -- so where are you developing this California
5 resource? I mean, what plays? Is it offshore, onshore?

6 DR. MEDLOCK: No, primarily it's onshore, it's in
7 the sort of Southern California San Joaquin sort of basin
8 area, so....

9 MR. WAYNE: Does that have to do with the heavy
10 oil production?

11 DR. MEDLOCK: It has to do with -- a lot of it is
12 associated production, but it is higher cost is the
13 bottom line and so that's why you don't actually see it
14 occurring. I guess it's a resurgence of fuel, although
15 it's modest, you know, against the backdrop of what's
16 happening in all of North America, but you do see a bit
17 of a recovery in California gas production, yeah, that's
18 right.

19 MS. VU: I would like to discuss one point about
20 production cost curves. What I notice is that, in the
21 gas industry and even the oil, it's very hard to fine
22 what is the production cost curve unlike our cost
23 information, unlike the electricity industry, you know
24 the production capacity, the generating capacity, you
25 know the marginal cost for production. For natural gas,

1 it's not that straightforward. The data on production
2 costs is really sporadic and people who are doing the
3 modeling need to have a lot of research and assumptions
4 to make that happen. Recently, one large independent
5 producer in the U.S., they claim that their production
6 cost is about \$4.60, but those are like a couple points,
7 not a lot of data around that.

8 DR. MEDLOCK: Right. So I guess what you're
9 asking is how do we develop our cost curves.

10 MS. VU: Yes, that would be helpful.

11 DR. MEDLOCK: No problem. That work is largely
12 done through reference to the Well Economic Model that
13 we've developed at the Baker Institute and it's specific
14 to different plays and different resources. And one of
15 the things we actually have access to, and I would highly
16 recommend the CEC, if they wanted to sort of pursue this
17 course independently, you know, pursue a sort of similar
18 vein in terms of the research that we do, we have
19 actually access to a database that is provided by a
20 company called Drilling Info which that database, they
21 recently bought HPDI, it is used in a lot of different
22 sort of industry studies. The reason it is used is
23 because it actually allows you access to well filed data,
24 so it is very specific data with regard to individual
25 wells that are drilled all over North America. And you

1 can actually use that well filed data to develop costs
2 and break even prices, if you will, for different wells
3 and you can then begin to understand whether or not wells
4 are sort of in the money or out of the money, if you
5 will, a very specific sort of data point basis. And what
6 that allows you to do is create aggregates of different
7 well types and that can go a long way and, in fact, it
8 does go a long way in defining sort of what the cost of
9 development for a particular well type in a particular
10 region, a particular play is, in North America. And it
11 is sort of the quick one-minute explanation, but in a
12 well file, you get a lot of information about where the
13 well is located, how much the well has actually produced,
14 not only in its initial phase, but over the life of the
15 well and, you know, the well life will be determined by
16 all sorts of characteristics that are associated with the
17 well and its location, not only by the play it's located
18 in, but also what it is competing against in that play
19 zone and so forth.

20 One of the things that you actually see, and this
21 is a tremendous sort of uncertainty going forward when
22 you're looking at that data over the last just five
23 years, you actually see that initial production rates for
24 different well types are consistently increasing. You
25 see that projected estimated recovery for specific well

1 types are also increasing, and what that typically tends
2 to do in a particular cost environment is drive down the
3 per unit cost. So, to the extent that that can continue,
4 that's definitely sort of a technology assumption that
5 you have to make going forward and, if it does continue
6 at the pace we've seen in the last five years, then that
7 really does challenge even the Reference Case prices
8 you're seeing here, you know, being in that \$5.00 to
9 \$6.00 window. In particular, they'll probably be lower.

10 MR. WAYNE: This is George Wayne again with El
11 Paso. Sort of a general comment. To me, it would be
12 helpful if you included when you're talking about these
13 price decks, particularly the U.S. Price deck or
14 forecast, you at least show alongside it, I know it's
15 volatile, but just sort of where the transactional curve
16 is, I know it's not a forecast, but just where the market
17 is transacting as far as oil or gas. And what I mean --

18 DR. MEDLOCK: In terms of the forward or something
19 like that?

20 MR. WAYNE: The forward curve, right.

21 DR. MEDLOCK: Yeah.

22 MR. WAYNE: And why that's important, and I see
23 it particularly in the Rockies where I cover it
24 extensively is, you know, producers will hedge, they
25 hedge a large amount of their gas production, and

1 depending on the price level and the shape of that curve,
2 will influence their cost and how they produce. So I
3 think just as a data point at least just always benchmark
4 your forecast against where the market is transacting is
5 helpful and insightful.

6 DR. MEDLOCK: I think it's a fair statement to
7 make, but it's also important when you do that sort of
8 benchmarking to understand liquidity in the curve and it
9 pretty much evaporates after about three years, so a lot
10 of what you see in terms of like what the NYMEX will put
11 out there in terms of what those prices are actually
12 listed, you'll see very little liquidity and a lot of it
13 is just based on a trend analysis over the previous three
14 years. So I think one of the things to do if that's
15 going to be the case is to make that point and maybe
16 perhaps actually put those liquidity markers which are
17 available on the NYMEX from the CME on a daily basis.
18 It's an important point, very important point.

19 MR. RHYNE: I'd like to ask one more question
20 and, actually, this question can help move us, I think,
21 away a little bit from the model itself. The model is
22 constructed on assumptions of economic behavior and it's
23 very strong in terms of that approach, but that's not the
24 only type of behavior that drives participants,
25 specifically developers and large scale consumers. It

1 would be interesting to find out from our panelists if
2 there are any roles for strategic behavior that may
3 deviate from the business as usual. And I'll give you
4 one example of that. The development of LNG export
5 capacity as a type of, say, hedging strategy to establish
6 some cost minimization approach in a future looking -
7 it's not a pure economic strategy, and yet it could be a
8 strategic strategy. What do our panelists think we may
9 see in terms of deviations from this business as usual
10 kind of economic approach?

11 COMMISSIONER PETERMAN: Well, as they are
12 thinking about that, I had a clarifying question about
13 LNG exports and, just to make sure I understand how it's
14 used in different scenarios. So I see in our high price
15 scenario, there is LNG export in that, and is that
16 because the high prices make it economic to invest in
17 LNG? Or is the causation reversed, that somehow --

18 DR. MEDLOCK: No, actually, yeah, that's a good
19 question. The way that's actually modeled is you get a
20 bit of a price uplift -- and there are other things going
21 on here, right, that help try that sort of high price
22 case, but there's an explicit assumption with regard to
23 the volumes that would be contracted for delivery outside
24 of North America from North America because, in the
25 Reference Case, there are no existing contracts. There

1 are some sort of non-binding agreements with regard to
2 the Cheniere facility that's been proposed for export in
3 the Sabine Pass region in Louisiana, with consumers --
4 potential customers in India and Europe, Spain in
5 particular and Portugal, but none of those are actually
6 binding commitments, and so in the Reference Case, you
7 don't actually have that hard coded as a contracted
8 delivery.

9 One of the things that is actually done in the
10 high price case is those contracted deliveries are
11 assumed to be binding, and so what you actually see is,
12 in effect, an increase in demand for North American gas,
13 which is what helps to lift price a little bit in North
14 America.

15 COMMISSIONER PETERMAN: Thank you for that.

16 DR. MEDLOCK: Sure.

17 COMMISSIONER PETERMAN: So, Panelists, do you
18 have any responses now to Ivin's question?

19 MR. WILDER: Scott Wilder, Southern California
20 Gas. I can say a little bit, although we're really a
21 distribution company and not involved in the actual gas
22 production, but a little bit related to what was just
23 discussed, you know, in the absence of long term
24 contracts, the generally like multi-billion dollar
25 expense of building an export facility, you would have to

1 have some kind of incredible strategic interest to do
2 that, to go against the current economic situation, or if
3 you had an economic outlook that was not favoring that,
4 if you were going on kind of a pure potential strategic
5 play. And I hope I'm understanding the question
6 correctly.

7 COMMISSIONER PETERMAN: So you're saying that one
8 wouldn't do it without the economic interest?

9 MR. WILDER: I think you would want to see the
10 economic interest either there or be fairly sure of the
11 probability somewhere five years or so out in the future.

12 DR. MEDLOCK: Yeah, just to sort of reinforce the
13 point that Scott is making maybe, even the CEO of the
14 controlling -- it's Apache for the Kitimat proposal, for
15 exports out of Kitimat in BC is on record within the last
16 six months as saying that one of the things that will
17 really sort of drive the full scale development of that
18 facility is the securing of long term contracts on an oil
19 index basis with customers in Asia. And certainly that
20 is appearing to be increasingly likely, but to date those
21 contracts are not in place. And so, in terms of the
22 Reference Case, you can't really go ahead and make an
23 assumption that they will be, which is why we do
24 scenarios, to sort of make that assumption that
25 ultimately they are, and try to understand what that

1 means, but sort of building -- you're absolutely right,
2 it is a multi-billion dollar sort of venture -- building
3 that at risk without that sort of contract underpinning
4 of the development, you're going to be hard-pressed to
5 find a bank that will underwrite that in sort of any
6 case, so you have to have a really large player that can
7 do it purely on sort of an equity basis and, even then, I
8 doubt there are many CEOs that would take that risk. So,
9 again, that's why we have to do it on a scenario specific
10 basis.

11 MR. WAYNE: I was going to say that -- this is
12 George Wayne again -- my only comment with regards to
13 that question is, on all the modeling that we do at El
14 Paso Corporation is we assume, you know, an economic
15 dispatch, I mean, particularly in the long run. And our
16 investors, our company are looking for some kind of an
17 economic return. I mean, we realize that there is
18 irrational or gaming that goes on in the market, you
19 usually see that on a day-to-day or over a very short
20 period of time; again, in the long run, we do assume
21 rational economic recovery of capital. So, I guess
22 that's probably really my only comment.

23 MR. WOOD: This is Bill Wood with the California
24 Energy Commission. With regards to things that could
25 impact the natural gas market that are not economical,

1 several come to mind, some of which we have included in
2 our scenarios, but basically it's areas in the area of
3 regulatory things that could happen like do you reduce
4 coal use in power plant generation, or don't you? Do you
5 have more strict RSP, or do you reduce it? Do you allow
6 fracking to occur for the development shale or other
7 resources, or don't you? Do you restrict certain kinds
8 of resources because of sensitivity in the particular
9 areas, or do you open up the resources? All of these
10 things can have an impact upon either the demand side or
11 the supply side that can impact in the market, that
12 aren't strictly economic. And there are probably more
13 kinds of regulatory things that I haven't mentioned here
14 that could also have those kinds of impacts. And I said
15 some of these we have included in the scenarios, but not
16 all of them.

17 MR. WAYNE: Well, I guess the only -- for all of
18 those particular points you're making, I guess we do try
19 to model or look at some kind of an economic
20 justification for them to go one way or the other with
21 regards to fracking, with regards to a lot of these
22 Renewable Portfolio Standards, greenhouse gas issues, the
23 like. We always come down to some kind of a price point,
24 a threshold that will move it one direction or another,
25 so we do -- we still try to base it on some kind of an

1 economic rationale.

2 COMMISSIONER PETERMAN: I have a quick question
3 for George since you're talking about that. When you do
4 that analysis, you have the existing statutes or what's
5 in the pipeline, but then do you look at extreme cases?
6 Do you look at RPS of 40 percent? Fifty percent? Even
7 though those aren't explicitly on the table now?

8 MR. WAYNE: Yeah, we do run, as you all have done
9 various scenarios or sensitivities to our base case, we
10 call it, to understand what the drivers of those
11 particular changes might be. And, I mean, I've looked at
12 all your sensitivity and base cases, those all seem
13 pretty reasonable and, again, very good things to do to
14 be able to test your Reference Case.

15 MS. VU: On the shale gas development from the
16 question, what I believe is the industry -- what they
17 push for is prudent development because it's a brand new
18 technology and also a lot of new production area has
19 different geography, so it impacts the local community
20 differently. So there are issues like recently in the
21 *Wall Street Journal* talking about water contamination,
22 possibly some chemicals from the fracking affecting the
23 water use, all of that needs to be addressed so that
24 there would be a public acceptance of the technology and
25 the development of the resources. The resource base is

1 so large, so therefore recently the NPC, the Natural
2 Petroleum Council came out with an assessment of the
3 resources, as well as the emphasis for best practices and
4 also prudent development, sharing the best practices and
5 proceeding with development in a very prudent way. And I
6 think there are laws from different states enacted to
7 make that happen.

8 DR. MEDLOCK: I'll just make an additional
9 comment on that point. A lot of the stuff that is
10 happening with regard to assessing the viability of shale
11 in the face of some of these concerns is happening in
12 real time, and so that's a very important sort of point
13 to sort of take on board when you think about the
14 modeling process because a lot of what has been done to
15 generate the Reference Case and the scenarios has been
16 done over the last six to nine months, in particular with
17 the cases that are being presented today, within the last
18 six months. And so, things that have sort of been
19 reported out by the NPC, in particular, the study that
20 was just released, was actually just released in the last
21 week, so you will not necessarily see a sort of full
22 incorporation of a lot of that consideration in, or a lot
23 of those sorts of studies in what is being discussed
24 today. And quite frankly, from a modeling perspective
25 that's one of the most difficult things to try to sort of

1 keep your head around because you're being asked to stay
2 on top of things that are happening in real time very
3 very rapidly, and on the policy front very very rapidly.
4 And it's not always possible to predict exactly where
5 sort of that's going to swing. So I think in the
6 scenarios that have been developed there was quite a bit
7 of trying to understand where that might actually go, but
8 you know, as with anything in the policy arena, it's very
9 very difficult to predict that outcome.

10 MR. TAVARES: Okay, I have a question for George.
11 I know, George, you do a lot of the modeling at El Paso
12 on the natural gas. Do you see, you know, the Reference
13 Case -- and again, we are not putting a special emphasis
14 on Reference Case -- but how do you see your prices, what
15 kind of a stream of prices do you have in your modeling
16 compared to what we have here on the screen? This is in
17 2010 Dollars per dozen cubic feet.

18 MR. WAYNE: Yeah, in our modeling we really, with
19 respect to the U.S. prices, our price forecasts, or
20 "price deck" that I like to call it, is in general
21 higher, probably -- particularly when you go further out
22 in the curve, a couple of dollars higher than what you
23 have in your Reference Case. Also, we don't have that up
24 there, but our assumption as far as oil-gas spread, at
25 least in the early part of the years, the next five

1 years, I call it a "medium term," our oil-gas spread
2 assumption or ratio is also wider than what you all show.
3 But it's interesting because, in general, the output of
4 your model is really not so much different than ours.
5 You know your high level themes as far as what's driving
6 demand growth across the U.S., your assessment of supply
7 and production, your assessment of even in the State of
8 California, you're going forward projection as far as the
9 California demand growth, is really not that far off from
10 ours, even in light of the fact that our price curves
11 diverge, again, more toward the back end, if that's
12 helpful.

13 MR. TAVARES: Okay, yeah. Thank you. Anymore
14 questions? Yes.

15 MR. KLATT: Hi. My name is Greg Klatt and I
16 represent Transwestern Power Plant Company. I just have
17 some questions regarding the Reference Case. The first
18 is that - and I don't know if you're prepared to get into
19 this level of detail, but I just wanted to go ahead and
20 at least get them out there. The reports Reference Case
21 projects a utilization of 37 percent on a segment of the
22 Transwestern Pipeline in the year 2022, I think it's the
23 West of Thoreau segment. And that just seemed like a
24 very dramatic reduction and utilization and I was hoping
25 you could shed some light on what the drivers are behind

1 that in terms of the Reference Case.

2 DR. MEDLOCK: Yeah, that's a very good question
3 and it's a very specific question, particularly when you
4 sort of ask anybody to project pipeline utilization in a
5 particular year, but one of the biggest drivers of the
6 outcome that you're actually seeing there is what's
7 happening with regard to demand for natural gas, west of
8 Thoreau, in particular. So in the California market
9 largely and that really falls primarily on the
10 assumptions regarding Renewable Portfolio Standards. And
11 the sort of other things that are more subtle that
12 haven't been discussed, but I think that will be later
13 today by some of the CEC staff with regard to assumptions
14 around efficiency improvements and other things that
15 definitely have a high level impact on gas demand. So
16 that's largely what drives that particular result.

17 MR. WAYNE: This is George Wayne again and,
18 again, that is a very specific question, I know we'll
19 probably get to those more granular questions later on
20 when you're going through your Reference Case detail or
21 your scenario details. But like with the Ruby Pipeline,
22 you show a very low utilization also for that. Now, in
23 going forward, just for an update, I mean, the Ruby
24 Pipeline roughly at 62 percent and growing utilization
25 rate, and you have it, I think, in the low 40's and,

1 again, in our modeling, we do show that dispatching
2 higher really throughout the 10-15-year period, and also
3 in our modeling of all the pipelines, even Transwestern
4 and others, we see higher utilization rates than you're
5 showing, although again it's interesting to see your
6 overall demand outlook for California as far as gas is
7 again pretty much in the ballpark, or fair away of what
8 we're showing, so there is maybe a little bit of
9 disconnect at how that's happening, but the output seems
10 reasonable, but some of the inputs and more granular
11 steps, there seem to be a few disconnects, but I'll wait
12 for --

13 COMMISSIONER PETERMAN: Well, I'll just
14 interject, George, I think this is the time to cover the
15 Reference Case, and so if you have specific questions,
16 please bring them up and also, being aware of the time,
17 if they are all not covered or answerable at this point,
18 please provide them in written comments because it would
19 be great for us to get that feedback.

20 MR. WAYNE: Well, I had that general comment, I
21 just see sort of like, again, sort of low utilization
22 rates a lot across a lot of these pipelines, particularly
23 coming up from the Desert Southwest, that is Transwestern
24 EP&G and even Kern.

25 MR. KLATT: Greg Klatt again. Could I just ask

1 you a question about --

2 COMMISSIONER PETERMAN: I want to get that
3 question answered first, though, pardon me, Greg. So
4 could you comment on that, Dr. Medlock just around the
5 relative low utilization rates on those lines? Thanks.

6 DR. MEDLOCK: No, absolutely I can offer up an
7 answer. A lot of it has to do with the manner in which,
8 quite frankly, California demand is met. You can do
9 things in the Reference Case, in particular, that will
10 sort of change the outcome. You know, it's kind of hard
11 to make direct comparisons between what is being done
12 with regard to the Reference Case or the base case, in
13 particular, in the El Paso consideration vs. the CEC
14 consideration vs. the SoCalGas consideration because, you
15 know, you really don't know at its face how the
16 assumptions compare. I think the comment about demand
17 being similar is important to understand, and so what
18 that leads you down the path of trying to understand sort
19 of beyond that point is, if the demand projections are
20 the same, how do projections with regard to capacity
21 utilization on Ruby, on Transwestern, on EP&G, on GTN,
22 how do those all compare? And what it sounds like
23 largely, the big swing source of supply with regard to
24 understanding the differences in the assumptions is going
25 to be primarily Canadian supply. And you know, it's hard

1 to say whether or not El Paso has the same assumptions as
2 SoCalGas, as CEC, as Rice University, with regard to the
3 cost of supplies that will be coming out of Canada,
4 relative to the Rockies, relative to the U.S. Southwest,
5 in particular, so I think that's really where the swing
6 is, trying to understand --

7 MR. WAYNE: Well, that's a good -- I'm sorry to
8 interrupt you -- that's a good point, but what I see,
9 though, is relatively to our cases, particularly Canadian
10 exports to the U.S., you are declining faster than we
11 are, so there's less gas from Canada coming into the
12 U.S., so again, which would mean higher utilization rates
13 on pipelines such as El Paso, Transwestern, Kern, and
14 others. So, again, I see a disconnect because I see less
15 imports from Canada, but, yes, I don't see more and
16 higher utilization rates.

17 MR. BENNETT: Or -- this is Lee Bennett with
18 TransCanada -- are you taking into account the shale
19 plays coming on, offsetting the conventional declines?

20 DR. MEDLOCK: Is that directed to me or George?

21 MR. BENNETT: Yes.

22 DR. MEDLOCK: Oh, absolutely, absolutely.

23 COMMISSIONER PETERMAN: Greg, I interrupted your
24 question. If you wanted to ask that, as well?

25 MR. KLATT: Oh, thank you. Greg Klatt again for

1 Transwestern. This actually goes into, at least
2 indirectly, the question that Mr. Bennett raised and that
3 is, in terms of the sources, supplies, we noticed that
4 for Transwestern, obviously we focused in on that, but
5 for Transwestern, the assumptions seem to be that it was
6 only connected with the San Juan Basin, when in reality
7 the Transwestern Pipeline System can access Permian
8 Rockies via TransColorado, Northwest, even Mid-Continent
9 and Shell supply areas. Are we just not seeing that
10 detail in there, or was it in fact the case that, for
11 purposes of the Reference Case you just made the
12 assumption that it was only San Juan Basin gas going
13 through Transwestern?

14 DR. MEDLOCK: If that's directed at me with
15 regard to how that is actually reported, it's probably,
16 well, I would say it is difficult for me to answer
17 because I do understand that Transwestern can reach back
18 definitely farther than just the San Juan Basin supply
19 region, but in terms of how that is actually being
20 reported and what you're seeing in the report that you're
21 referencing, it's difficult for me to say. I really
22 don't know. So I think that's probably going to have to
23 fall on the CEC staff, quite frankly, in terms of how
24 that report was generated to answer. I don't know, Leon,
25 if it falls on you, or that falls on Ruben, or who, but

1 hopefully we can address that today, or if not today,
2 later.

3 MR. RHYNE: So we'll definitely try and get that
4 answer for you. I don't know that we can guarantee that
5 we'll have it for you today, but we will certainly
6 address it to you.

7 MR. WAYNE: One general comment, I do plan on
8 leaving with you at least the slides that you provided as
9 far as your Reference Case breakout. We did a side-by-
10 side comparison, at least our forecasts along with each
11 one of those criteria, and I'm going to leave that with
12 you all so you can use it at your liberty.

13 COMMISSIONER PETERMAN: I appreciate that,
14 George. And also, I appreciate your insight into,
15 whether now or later, into fundamentally what the price
16 implications from the assumption of the lower utilization
17 of the gas lines you identified; being in a regulator
18 position, I'm trying to take it to the high level and
19 think, okay, how does this impact exactly what we're
20 looking at? And so I appreciate your thoughts about how
21 much that will move things, or whether it is more of a
22 technical concern.

23 MR. TAVARES: Okay, any other questions,
24 comments?

25 COMMISSIONER PETERMAN: And Dr. Medlock, do you

1 have any additional statements you want to offer now?

2 DR. MEDLOCK: Other than the fact that I think a
3 lot of the feedback is welcome and I think very good,
4 there's not a lot with the exception of, you know, it's
5 important to understand that, if we're going to focus on
6 a discussion at the end of the day about capacity
7 utilization, you know, and sort of one particular case
8 vs. another, and one particular set of sort of scenarios
9 that have been developed by either El Paso, or SoCalGas,
10 or CEC, or TransCanada, or you know, so on and so forth,
11 it's important to understand if we're focusing on
12 capacity utilization, in particular, that we need to also
13 compare what's the baseline assumption with regard to
14 capacity itself and demand, and make sure that we're all
15 on the same page there if we're going to go forward with
16 a discussion about capacity utilization. And I think
17 that's probably a little bit more difficult to do, it's
18 more of a longer term kind of answer, if you will, than
19 what we can probably address in one afternoon. So,
20 that's really it.

21 MR. TAVARES: Okay. Commissioners, it is almost
22 12 o'clock. If you want to, we can break here and come
23 back around 1:00?

24 COMMISSIONER PETERMAN: That would be great.
25 Let's take a lunch break and see you all here at 1:00.

1 MR. TAVARES: Thank you.

2 (Break at 11:58 a.m.)

3 (Reconvene at 1:06 p.m.)

4 MR. TAVARES: Okay, we're going to start right
5 now. Are you ready, Commissioner? Okay. Our next
6 speaker is Leon BRATHWAITE. He is part of the staff here
7 at the Commission and he is going to talk about the high
8 gas price, low gas price, and also the Constrained Shale
9 Gas. Leon.

10 MR. BRATHWAITE: Thank you, Ruben. Good
11 afternoon, Commissioners. I am Leon BRATHWAITE, as Ruben
12 said. Good afternoon to the audience also. I work here
13 at the CEC in the Electricity Analysis Office. I want to
14 present to you what we are calling the "National Cases."

15 These cases, we are calling them the "National
16 Cases" because they do not specifically focus on
17 California. We are looking at the Continent as a whole;
18 but as you know, California is connected to the rest of
19 the Continent and connected to the rest of the world, to
20 LNG, in particular, for the rest of the world, so things
21 that are happening far away from here could have impacts
22 right here at home.

23 So anyway, this morning, Dr. Medlock spoke a lot
24 about the Reference Case, and I will not duplicate that
25 presentation or the information that was provided there.

1 What we'll be looking at is what assumptions did we make
2 relative to the Reference Case, what changes did we make
3 to the Reference Case? We use the Reference Case as our
4 starting point -- what changes did we make. And that is
5 what I will be focused on. And then, when we look at
6 results, we look at results in relation to the Reference
7 Case. So I am not going to be talking about the
8 Reference Case, even though I'm sure if you have any
9 questions about it, I'll try and answer them and I think
10 Dr. Medlock is still on the line. Okay.

11 So, before I get into the presentation itself,
12 let me just kind of give you a roadmap of where we're
13 going to go. First, we'll talk about the purpose of the
14 cases, we'll talk about major policy issues that we
15 looked at in terms of designing the cases, we'll talk
16 about what are the national cases, then we look at a case
17 description, we look at a general impact or price changes
18 because that's important to the results, or the
19 explanation of the results, I should say, then we'll look
20 at the performance of the cases. We will look in terms
21 of price and in terms of the impact upon the supply
22 portfolio, and then we'll look at the difference in
23 results, and then we'll draw some very broad conclusions.
24 I am sure when it is over, we can come up with a lot
25 more, but we'll see what we come up with.

1 Okay, so the purpose of the cases. Well, we were
2 trying to look at what are the potential vulnerabilities
3 to California, what are the potential opportunities to
4 California? As you know, in terms of supply, we have 85
5 percent -- 85 percent of the gas that is consumed in
6 California emanates from some source outside of
7 California. So we were looking at what are the
8 opportunities for California in terms of a supply
9 portfolio. We also wanted to look at natural gas price
10 and supply uncertainty. We also wanted to look at the
11 impacts upon the portfolio by looking at the relevant
12 policy initiatives in isolation, as we did in one of our
13 cases, or in combination with other parameters. And
14 finally, we wanted to develop a plausible range of price
15 and supply outlook, all right? A plausible range --
16 please, on the line, "plausible," okay?

17 So what are the major policy issues that we're
18 dealing with? Number one of course is the implementation
19 of the Renewable Portfolio Standard, that of course is a
20 big conversation ongoing here in the state. We're also
21 looking at the conversion of coal-fired generation. We
22 further looked at the environmental mitigation costs of
23 shale development, of course another big conversation
24 that is ongoing. But, in particular with the shale, we
25 were looking at water use and disposal, which are causing

1 a lot of discussion in the regulatory environment as to
2 what we really do about a lot of the water that is being
3 used to develop the shales. Now, I just want to make one
4 point here. This morning, somebody said that the
5 technology where shale development is concerned is new; a
6 little correction, it is not new. Thirty years ago, I
7 was fracking wells in East Texas, okay? Just note. But
8 it wasn't new then either. But it is a technology that
9 has been modified and reconfigured and is now being used
10 to develop the shales.

11 Lastly, licensing of liquefied natural gas for
12 export, all right, that is something that is currently
13 ongoing. We have Kitimat in Canada, is probably a very
14 close to having a full export license, maybe someone in
15 the audience can tell us what is the status of Kitimat in
16 that regard. I just understood -- someone just told me
17 that Jordan Cove just applied for a DOE export license.
18 So exporting of natural gas, of LNG, will become
19 something, will become a part of our future.

20 So what are the National Cases? Well, the
21 National Cases are as follows: we had a High Price case,
22 a Low Price case, and we had a Constrained Shale case.
23 So what I'll do now is try to describe to you what were
24 the changes that we made. Now, remember, we are talking
25 about changes relative to our Reference Case, okay,

1 *relative.* Don't get lost on that point.

2 So what did we do? And maybe I should move my
3 slide along. We removed about 50 GW of coal-fired
4 generation, and this came from the Brattle Group
5 analysis. We also assumed economic growth is going to be
6 kept at about 3.5 percent -- we can call that robust. We
7 also delayed the implementation of the RPS by an
8 additional 10 years. This was driven by the fact that
9 maybe at a State level we'll have some budgetary concerns
10 about the funding for some of these programs. Then,
11 starting in 2016, we assumed robust energy export
12 capability. Now, just the capability, okay? That was
13 developed and utilized at Kitimat, at Sabin Pass, Lake
14 Charles, Freeport, Cove Point, and as I just said, Jordan
15 Cove, which this is not in our model, but Jordan Cove
16 just applied for a license at the DOE.

17 Moving along. We also assumed -- I mentioned
18 about some of the environmental issues related with shale
19 development -- we did assume that there will be
20 additional costs, compliance costs, in the development of
21 shales. So we added \$.40 to the O&M production costs for
22 the development of shales and we added \$.20 for that of
23 conventional resources. Further, we removed from
24 development certain resources, particularly in particular
25 regions, in Pennsylvania, in New York, Colorado, Wyoming.

1 As a result of that, we shrank the resource base by
2 almost 18 percent. And on the international front, we
3 did introduce constraints on development in certain
4 places like Iran, Iraq, Venezuela and Russia.

5 So this is what our Supply Cost Curves look like.
6 The green is a 2007 Reference Case, that's the green
7 right here, the red is the High Price case, the case that
8 we are discussing right now, and the blue is our 2011
9 Reference Case. So we see we have a pretty good spread
10 here, this is the shrinkage that has occurred. But what
11 you should note here, obviously, it is quite obvious,
12 that we have a very flat portion of these curves here.
13 So if we really and truly want to move prices, if you
14 want to move prices in one direction or the other, you've
15 really got to do something about this flat portion of the
16 curve, which is very difficult to do, given the abundance
17 of resources that we have right now.

18 Okay, let's talk a little bit about what we did
19 in constructing our Low Price case. Well, we assumed
20 that all states meet the RPS targets on time, of course
21 this will dampen natural gas demand; we kept long term
22 economic growth at about 2.1 percent, sort of -- you
23 could call that probably weak economic development; we
24 disallowed oil LNG exports as opposed to what we did in
25 the high price case where we allowed it, we disallowed it

1 here, we are keeping North America somewhat isolated; and
2 we assumed technological development will occur at about
3 2.5 percent per year - in the Reference Case, it is
4 somewhere around one percent, maybe slightly less than
5 one percent. We also assume a larger resource base and
6 we shift the curve about 5.8 percent to the right. And
7 in this case now, as opposed to our High Price case, we
8 allowed Iran, Iraq, and Venezuela to enter the market
9 unimpeded beyond 2015, I believe it was.

10 Okay, so here we have the supply cost curves for
11 our Low Price case. Again, the green is from 2007, the
12 blue is our 2011 Reference Case, and the red right there,
13 the red, is our Low Price Case that shows the 5.8 percent
14 expansion in our -- I'm sorry, this is all Low Price case
15 -- that shows the 5.8 expansion of the resource base.

16 The other case that we looked at was the
17 Constrained Shale case. As I said earlier on, there are
18 a lot of issues, environmental issues related to the
19 development of shale. One of them, one of the biggest
20 issues is the use and disbursement of water. I mean, every
21 frack job requires in the millions of gallons, I think
22 it's like anywhere between two and four million gallons
23 of water. So the question then becomes where does that
24 water come from, and after we are done fracking a well,
25 and we have drawn the water from the well, what do we do

1 with it? It is a very very big issue. So we tried to
2 see if we could come up with some idea as to, in handling
3 that water, what if there is a cost in terms of
4 production in developing shales. So we added \$.40 for
5 shale development in terms of production cost and added
6 \$.20 for conventional resources. So the resource base in
7 this particular case remains unchanged as compared to the
8 Reference Case.

9 So before I get into the actual results, I just
10 want to talk a little bit about what price changes do in
11 the oil cases. Now, we designed these cases to get
12 prices to move in one direction or the other, either
13 high, or low, or something in between, okay? So higher
14 prices as you know from Economics 101 will tend to
15 depress demand and it will stimulate supply; lower
16 prices, on the other hand, stimulate demand and suppress
17 supply. So usually, though, it is some combination of
18 those impacts that will occur, and it's rather difficult
19 sometimes to discern exactly what the impact is, or where
20 the impacts are, I should probably say. But price
21 changes do something much more important, well, probably
22 as important, it reconfigures your supply portfolio.
23 This is what happens. So whenever you see a price
24 change, some resources will become attractive and some
25 resources that were previously attractive become

1 unattractive. So what happens is that you end up with a
2 supply portfolio that may look different -- sometimes
3 radically different -- than what you started with. So we
4 will try to look at that reconfiguration of the supply
5 portfolio as we go through the results of these cases.

6 So let's talk a little bit about the performance
7 of the cases and let's focus on the Lower 48; remember,
8 these are National Cases, okay, not California specific.
9 So here we have the price. Now, we are using Henry Hub
10 as a sort of national price, as a sort of gauge of prices
11 on the Continent, and you can see prices are behaving as
12 expected, the High Price is on the top, the Low Price is
13 on the bottom, and the Reference Case, which is the blue
14 line, is in between and you have your Shale Constraint
15 case which is above the Reference Case for the most part,
16 but it does touch it at certain points. What we have
17 done here really and truly is to create what we have
18 called the "Zone of Uncertainty," some people call it a
19 "Cone of Uncertainty," but, you know, a cone is a three-
20 dimensional object, but anyway.... We have created a zone
21 of uncertainty where we believe it is plausible that
22 prices could fall within this zone over the forecast
23 horizon, we don't know exactly where, but we just say
24 that is all a plausible zone of uncertainty.

25 This here measures the price differentials we use

1 in Topock, which is a pricing point in the southern part
2 of the state, and Henry Hub, which is our national price.
3 What we are seeing here is that somewhere around 2013,
4 our price differential will go from positive to negative.
5 The question then becomes why. Why do we see this
6 behavior? Well, I want you to think about these prices,
7 think about Topock as a Western price and think about
8 Henry Hub as some sort of Eastern price. Everybody with
9 me so far? Now, Lippman Consulting, which is one of the
10 people who provide us a very nice production database
11 that we use here at the Commission, define what he calls
12 the "Big Six," that is the big six shale plays, and they
13 are the Marcellus, the Wood Ford, the Haynesville, the
14 Barnett, the Fayetteville, and the Eagle Ford. Now, if
15 you look at a map of the United States and look at where
16 those shale places are located, nearly all of them, if
17 not all of them, are located in the eastern half of the
18 United States. So what is happening is that shale, which
19 produces over 21 Bcf in August, most of that production
20 is occurring in the eastern half of the United States.
21 So that grid among the production that is occurring there
22 is suppressing prices, and I don't mean that as a bad
23 thing, but it is suppressing prices more in the east than
24 it is doing so in the west. So this is why we are seeing
25 this conversion from a negative differential to a

1 positive differential after 2013.

2 Now let us look a little bit at the supply
3 portfolio. So here we have the United States, right, the
4 Lower 48, we have production running about 69.2 Bcf, and
5 we have demand running about 71.1 Bcf per day. So what
6 we can say here, though, is that we have two main
7 demands, we have end-use demand and we have exports,
8 which is represented right here. And we have three
9 items, or three elements in our supply portfolio trying
10 to satisfy that demand; we have Canadian Imports, which
11 is bringing about --- and I'm using 2025 as my snapshot
12 here --- which is bringing about 10.5 Bcf a day, we have
13 of course the Lower 48 production trying to satisfy
14 demand, and we have LNG imports which is running about
15 1.7 Bcf a day. Now, this is a supply portfolio in the
16 Reference Case. Now, what happens when prices change?
17 This is what I am speaking about when I talk about a
18 reconfiguration of our supply portfolio.

19 So let us look a little bit at the High Price
20 case. In the High Price case, we see Henry Hub prices up
21 about 8.5 percent. We still have our two main demands,
22 end-use demand which is up about 1.1 percent, and export
23 which is up almost 10 percent. Now, you may look at that
24 and say, "Well, you know, Leon, that contradicts what you
25 just said. If prices are up, demand should be down."

1 Well, we are doing other things in this case, this is a
2 case that we did in combination, we are doing other
3 things. In this particular case, we have robust economic
4 growth, capping at about 3.5 percent. We also have the
5 conversion of coal, 50 GW of coal conversion to gas. So,
6 even though prices are up, we also have end-use demand up
7 because of the other things that we are doing within the
8 case. So what is satisfying this demand? We have
9 Canadian imports, which is up 25.2 percent, we have Lower
10 48 production, which is down about 8.8 percent. And the
11 reason for that is because of the increased costs on
12 shale that we have assumed in this case. But we have LNG
13 imports coming in to also satisfy demand, and that is up
14 about 290 percent, you know, it's a little bit up, it
15 started off small, so it looks like a big number, but it
16 is only 6.9 Bcf per day coming in. So what we are seeing
17 here is that the elements of our supply portfolio are
18 competing to satisfy the demand, that is what is
19 happening. And this is what is causing the
20 reconfiguration of our supply portfolio as things that
21 were once attractive become unattractive, and things that
22 were unattractive previously now become attractive.

23 Now, let us move to our Low Price case. In the
24 Low Price case, we see prices, Henry Hub prices, down 7.6
25 percent, end-use demand up as you would expect 4.7

1 percent, no change in exports, we are not allowing
2 exports -- we are not allowing LNG exports in this case.
3 Demand is satisfied by Canadian Imports which is up 8
4 percent; Lower 48 production, which is up 3.9 percent;
5 but LNG imports are down almost 15 percent. But in this
6 case, you can see production is running almost 72 Bcf/d
7 in 2025, the Lower 48 production, and Lower 48 Demand is
8 running at almost 75 Bcf/d, and there we have all
9 elements again and we see the reconfiguration of the
10 supply portfolio, the elements satisfying our demand.

11 And if we look at the Shale Constrained case, we
12 see that end-use demand, we see prices down 1 percent,
13 but end-use demand is also down 3.2 percent. Well, there
14 is a little anomaly here, well, it's not really an
15 anomaly, okay, prices in previous periods also affect the
16 prices in the current period. So in this case, the
17 previous period, prices were up actually about 3 percent,
18 so as a result, some of those lingering effects are
19 showing up in the current period and we see end-use
20 demand declining about 3.2 percent. So what is happening
21 here? We have demand being satisfied by Canadian
22 Imports, which is down about 15 percent, you remember
23 end-use demand is also down, Lower 48 production is down
24 about 2.8 percent, and LNG imports are up almost 5
25 percent. Again, we see the reconfiguration of our supply

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1 portfolio.

2 So let us now look at the performance of the
3 cases here in California, even though these cases did not
4 specifically focus on California, but California is
5 certainly impacted by the changes that we made on the
6 national level.

7 So if we use Topock as our pricing point, we can
8 see that we have prices, High Price on top, Low Price
9 below, the price range in our zone of uncertainty is
10 running somewhere about \$5.25-\$5.50, all the way up to
11 north of \$7.00; again, we have our zone of uncertainty,
12 we don't know where prices are actually going to be, but
13 they are somewhere in there, we believe that is our
14 plausible zone of uncertainty, if you can call it that.
15 Now we can look at our supply portfolio. This is for the
16 reference case here in California. We have essentially
17 one demand, this is end-use demand. And how is it
18 satisfied? It is satisfied by Canadian Imports, Rocky
19 Mountain supplies, southwest supplies, and local
20 production. When I say "local production," I'm talking
21 about in-state California production.

22 So if we look here, we'll see our demand is
23 running about 6 Bcf/d -- this again is in 2025 and I'm
24 using that as my snapshot here. So we have demand at
25 about 6 Bcf/d, we have Canadian imports coming in about

1 2.4 Bcf/d, Rocky Mountain is providing about 1.25 Bcf/d,
2 Southwest is providing about 2.25 Bcf/d, and our local
3 production, not much, just .2 or .3 Bcf/d, all
4 struggling, all competing to satisfy that demand.

5 Now, when we go to the High Price case, what do
6 we see? Well, prices are up 7.8 percent and, again, we
7 are still using Topock as our reference price here.
8 Prices are up 7.3 percent, end-use demand is down about 2
9 percent, Canadian Imports also down 9.7, Rocky Mountains
10 down 7.4, Southwest supply, though, increases 4.5
11 percent, and local production also increases 28.5
12 percent. What we are seeing, again, is that
13 reconfiguration of our supply portfolio that I've been
14 stressing so far.

15 In the Low Price case, again, we have price is
16 down, demand is up, and we have a variety of things
17 struggling to supply the demand. We have Canadian
18 imports up about 10 percent, Rockies up about 3 percent,
19 Southwest dropped off a little bit, 4 percent, and local
20 production is up about 30 percent. Again, all resources
21 there competing to satisfy that demand.

22 In the Constrained Shale case, though, we had
23 prices down about .6 percent, less than 1 percent, but
24 end-use demand also down about 3 percent. Now, this is a
25 case where the prices in the previous period is affecting

1 our outcome in the current period. Prices were up about
2 3 percent in the previous period, those are Topock
3 prices, and that resulted net downward pressure of end-
4 use demand in this period. So what is happening here?
5 We have Canadian imports down about 6.4 percent, Rocky
6 Mountains down about 4 percent, Southwest supply up less
7 than 1 percent, and local production up about 5 percent.

8 So let us talk a little bit about the Difference
9 Results. The Difference Results is where we look at the
10 entire 2005 all the way to 2030, and we are trying to
11 discern what is going on in all cases relative to the
12 Reference Case. So what we see here is that higher
13 environmental mitigation cost is reconfiguring the order
14 of selection of these resources. So, as a result, in
15 your High Price case and your Shale Constrained case,
16 production moves lower overall. Okay, this is production
17 from all sources and we are looking at the difference
18 here. And that difference is defined as a case of
19 interest minus the Reference Case. So, production moves
20 lower, we have a lower production in these cases because
21 of that higher cost that we have put on the shales and on
22 the conventional also. In the Low Price case, however,
23 as LNG is pushed out because of the low prices, we have
24 local U.S. production coming in, the Lower 48 production
25 coming in, to take its place. So we are seeing that,

1 because of the higher demand and because of the lower
2 prices pushing out LNG, we are seeing increased
3 production in our Low Price case.

4 In our shale, when you look at the difference
5 where shale is concerned and, again, we are looking at
6 the difference, and that difference is defined as a case
7 of interest minus the reference case. And you see a
8 similar pattern here. You see a similar pattern here
9 where increased cost is pushing shale production down
10 and, in the Low Price case we are seeing shale production
11 because LNG is being pushed out and demand is higher, so
12 we have more production from shales as a result of those
13 two phenomena.

14 Now, let us look a little bit at the U.S. Demand.
15 Now, in this particular case, higher prices push demand
16 lower in the High Price case and in your Constrained
17 Shale case. Now, in the High Price case, robust economic
18 performance and coal conversion is pushing demand higher
19 after 2022, which is what we are seeing right here, that
20 of course is a zero line and we see higher demands there
21 as a result of our coal conversion and the robust
22 economic performance that we assumed.

23 Now, if you look here, this is a continuation of
24 the previous slide, we have low prices stimulating demand
25 in the low price case, pushing demand higher, and

1 remember here that all the states are meeting the RPS on
2 time in this particular case, the Low Price case, so it
3 dampens natural gas demand between 2012 and 2022, so that
4 is what we are seeing is that dampened effect in this
5 particular case right in there where it is not seeing
6 much movement on the natural gas demand as a result of
7 the implementation of the RPS Standards.

8 Now, if you look at power generation by itself,
9 in the High Price case power generation demand climbs
10 higher as robust economic performance and coal conversion
11 pulls in a lot more gas, and this is what we are seeing
12 here with this case here. We see a lot of power
13 generation is very strong, a lot of natural gas being
14 demanded in that sector.

15 Okay, so can we make some broad conclusions?
16 Yeah, we can. Added environmental mitigation costs may
17 delay the development of shale formation, obviously, if
18 some of the issues surrounding the development of shales,
19 whether it is about fracking, or whether it's about the
20 water use, these things may cause either the delay or the
21 complete cancellation of development of shales in some
22 places, and that is showing up in some of the work that
23 we have done. Price changes obviously can reconfigure
24 our supply portfolio, I think we demonstrated that with
25 the slide we just showed a little while ago. And as a

1 result of the work we just did, we were able to produce a
2 plausible range of price and supply outcomes -- remember,
3 a *plausible* range, that is what we are aiming for.

4 Now, it is possible -- it is possible -- for us
5 to go back in there, make some assumptions, and we can
6 get a wider range if that is the desire of anyone, or if
7 the Commissioners so choose; but this is what we have at
8 this point in time, and this is what we have been willing
9 to work with; if we have input that says differently, if
10 there are other plausible inputs that we can come up
11 with, we can easily go back and widen that range if it
12 becomes necessary. With that, I will open myself up to
13 any questions or comments, or anything else that you may
14 have. Thank you.

15 COMMISSIONER PETERMAN: Thank you, Leon. I don't
16 have any questions or comments, but I am interested in
17 hearing the Discussants' response regarding the
18 plausibility of this range. The assumptions seem to make
19 sense to me, but it would be great to hear if there is
20 anything that you think we missed, or whether you have
21 concerns around the Low or the High end of these
22 estimates. Thanks.

23 MS. VU: I have two questions. The first one is
24 for verification. The Constrained Shale case.

25 MR. BRATHWAITE: The Constrained Shale case.

1 MS. VU: Yes. The only difference between that
2 and the Reference Case is the environmental cost. Is
3 that correct?

4 MR. BRATHWAITE: That is correct, yes.

5 MS. VU: So it is not as constrained as the High
6 Price case.

7 MR. BRATHWAITE: Right, yes, you consider --

8 MS. VU: Because in the High Price case, not only
9 do you have the environmental cost, you also have the
10 reduction in the resource base.

11 MR. BRATHWAITE: That is true, yes.

12 MS. VU: So thank you for that answer. The
13 second is more like an observation. The price range now
14 in 2010 Dollars --

15 MR. BRATHWAITE: Yes.

16 MS. VU: -- now is between \$5.00 and \$7.00.
17 Again, when we look at all of those scenarios, the
18 industry, as well as the EIA, would show much larger
19 variations, somewhere between \$4.00 and \$9.00 or \$10.00.

20 MR. BRATHWAITE: Okay.

21 MS. VU: Right. So that is one observation --

22 MR. BRATHWAITE: Okay, could I respond to that
23 before you continue? Okay --

24 MS. VU: And then the other observation is, in
25 terms of demand across these scenarios, it is a very

1 tight range again, it is 27 to 29 Tcf, right? So we are
2 currently in about 22 Tcf of market, so we see from now
3 until 2030 the variation in demand is only 2 Tcf, between
4 27 and 29, which to me is a very tight range. Another
5 one I observe is the production range has higher
6 variation, but relatively tight, it is 24 to 28 Tcf, so
7 it is a 4 Tcf range instead of 2 on the demand side. The
8 EIA from their work is 22 to 30 Tcf, just those are the
9 observations. So, in my view, because of the supply cost
10 curve, marginal cost curve is relatively flat for the
11 first 600 Tcf of cumulative production, when you run
12 through these cases, it doesn't change the price very
13 much, as well as demand. So that is my observation.

14 MR. BRATHWAITE: And you are absolutely correct,
15 that flat portion of the curve, and I think I said this
16 in the presentation, is that that flat portion of the
17 curve makes it rather difficult to move prices in, shall
18 we say, a more extreme way -- not that I intend to be
19 extreme, but you get my point. But another thing that I
20 want you to remember here, these prices that we are
21 presenting here are annual averages, okay? So if you
22 look at the futures market today and, you know, it's
23 probably up ten cents, 20 cents, 50 cents, or whatever it
24 is, these are not what we are trying to reflect here, we
25 are reflecting annual average prices, okay, so that is

1 one thing I would like you to remember.

2 Now, as to the actual range of our zone of
3 uncertainty, sure, we can go back and look at some of our
4 assumptions, we can add new assumptions, and we can widen
5 that range, it is possible to do that. The question is
6 that, if we have an input that can give us some plausible
7 assumptions that we can work with, we can certainly
8 incorporate it in our future work.

9 COMMISSIONER PETERMAN: Leon, just following up
10 on that, before going back and adding things to the
11 model, I would just appreciate getting some feedback from
12 staff and whoever comments, stakeholders, about where the
13 key assumptions where we differ from the EIA, the EIA
14 that would affect that upper level bound on price, it was
15 mentioned earlier, some differences in terms of treatment
16 about shale production, and I don't know if there are
17 other ones that people can highlight right now that might
18 be a difference?

19 MR. WAYNE: I have some general comments. I
20 mean, overall, like I said before, our prices for the oil
21 spread is wider and our prices climb higher --

22 COMMISSIONER PETERMAN: George, sorry to
23 interrupt, would you mind turning on your mic or bring it
24 closer to you?

25 MR. WAYNE: Sorry, I thought it was on. I was

1 just saying, one general observation about price, our
2 prices start higher and they end higher than what you
3 have, and pretty consistent with sort of what EIA and
4 others are projecting. And our oil and gas spread is
5 wider than what you all, to begin with and sort of ending
6 with, is different. I agree with the lady to my right
7 that your high and low and constrained cases are probably
8 too narrow, I think they need to be maybe wider
9 sensitivity, though you can see the overall effect
10 better, I think, because I agree that the difference
11 between 25 and 27 Tcf over a year is a pretty narrow
12 range to be able to really see the effect you might
13 expect. If I look at, I guess, the High Price national
14 case, what I was surprised by is you have increased
15 exports and obviously a heck of a lot more increased LNG
16 imports; I just think not only from a policy perspective,
17 but even speaking in economic terms, if we have a High
18 Price environment here in the U.S., I just have a hard
19 time imagining that we would allow exports out of the
20 U.S. of gas, we would be producing more LNG imports
21 possibly, but definitely more production, but I can't
22 imagine we would be exporting gas in that kind of
23 scenario.

24 MR. BRATHWAITE: George, these are contracted
25 flows here.

1 MR. WAYNE: Excuse me, Leon? Sorry.

2 MR. BRATHWAITE: These are contracted flows.

3 MR. WAYNE: Contracted flows?

4 MR. BRATHWAITE: Yes, the LNG exports are
5 contracted.

6 MR. WAYNE: Yeah, but most of those LNG exports
7 are -- they have options. Most of those holders have
8 options to either take gas from the U.S. or Asian
9 markets, or other places, and again I think from that
10 standpoint, but also from a policy standpoint which would
11 get in the way, I just don't think the U.S. would allow
12 exports in a high price environment -- higher price
13 environment. I know it's relative.

14 I think you also need to look at your Canadian
15 imports and where I think you need to look at that is
16 really your marginal costs for like Horn River and
17 Montney. It appears to me you just have too much, or too
18 rosy of a picture for Horn River and Montney Development.
19 I mean, all the studies I've seen show, particularly Horn
20 River gas, shale gas, is much higher marginal cost than
21 really any of the shale plays. It's more remote, it has
22 much higher CO₂ concentration, which is also additional
23 cost, and that's not pegged for an import to the U.S.,
24 Lower U.S., that should probably more than likely be
25 pegged for export if that were to occur, so it's not

1 going to -- maybe in the worldwide supply demand balance,
2 but it's not going to really have much of an impact in
3 the national supply demand balance because, again, it's
4 going to be a hard time for it to develop, but if it does
5 get developed, it's more than likely going to be
6 earmarked for export.

7 Going back to the definition of shales, I guess
8 you have the slide up here, there are no shales in
9 Colorado or Wyoming as far as gas shales that are going
10 to be developed. I mean, there are oil shales, and some
11 of those oil shales do have associated gas within, but
12 it's de minimus, it's very small. So, I'm sort of
13 confused by that slide because, again, there are really
14 no oil shale gas shales to be developed in Colorado and
15 Wyoming over the particular time frame. Again, there are
16 oil shales, so they do produce a little bit of liquids
17 and associated gas, but it's de minimus in the scheme of
18 things to have any kind of impact. So, again, I'm sort
19 of surprised by that. So, I guess, off the cuff, those
20 were sort of my general observations.

21 MR. BRATHWAITE: About a policy concerning the
22 export of LNG, I mean, we did not model that policy, in
23 particular, to say that, you know, "If the prices get
24 above a certain level, all energy exports will be
25 forbidden." We did not think about doing that. But, I

1 mean, like I said, you know, at some point in time, we
2 could probably look at that.

3 As to Colorado and Wyoming, there are natural gas
4 production in those spaces that do have some shales, that
5 is what we turned off. I mean, maybe you are right, I'm
6 not going to argue the point, and maybe you are right,
7 that is not a lot, but there is some.

8 MR. WAYNE: There is very very little. I mean --

9 MR. BRATHWAITE: Okay.

10 MR. WAYNE: I mean, the Rockies as a whole is 11
11 Bcf a day market and, again, any shales that are
12 producing gas, or associated gas, and that is from the
13 Niobrara and maybe some from the Bakken, those oil shale
14 plays create some associated gas, but that might be 2
15 percent, 8 percent, of the total product, it's just not
16 very much at all.

17 DR. MEDLOCK: No, it's very small, actually. The
18 biggest point about this case is that the shales that
19 were sort of really hindered the most were the Marcellus
20 and the shale in the Pennsylvania and New York regions,
21 so -- the stuff in Colorado and Wyoming is tiny, I mean,
22 it doesn't really amount to much in terms of what the
23 model output is, so....

24 I actually have a comment about - you made a
25 comment about the Horn River and I actually happen to

1 know of a couple of developments up there that are not
2 tied to any LNG export facilities, that are tied directly
3 to expansions of the pipeline and gathering systems and
4 expansions of storage facilities up in the sort of
5 northeast British Columbia area that really are targeting
6 developments to be moved in existing pipeline
7 infrastructure, so I actually would disagree with the
8 comment that it's all targeting exports.

9 MR. WAYNE: Well, all those pipeline settlements
10 that I'm aware of are really gathering system, maybe some
11 short haul laterals to get gas to either the West Coast
12 Pipeline, the Spector Pipeline, to bring it further into
13 British Columbia, or maybe into the AECO System. But
14 probably the bigger project is, again, building a
15 pipeline over the LNG Kitimat liquefaction plant.

16 COMMISSIONER PETERMAN: Lee, I see you giving
17 some nods back and forth, up and down, so let's hear your
18 thoughts.

19 MR. BENNETT: Well, I guess our position is that
20 we do see Horn River and Montney being developed and the
21 flows going forward, though, those additional supplies
22 are going to offset the decline that we're seeing in
23 conventional. And we'll basically bring TransCanada --
24 or not TransCanada -- but the WCSB back to kind of the
25 peak levels that we had seen, I believe it was in 2001

1 type time frame, so that was the reason I was shaking my
2 head a little bit.

3 MR. WAYNE: Well, one good point, one I want to
4 bring up, I think you need to include in your modeling,
5 is the implication of -- and you can probably speak to it
6 more -- is Transcontinental's long haul system bringing
7 gas from Western Canada to the Eastern markets. Right
8 now, it's very very low utilization rates, TransCanada is
9 obviously wrestling with that and trying to rationalize
10 their rates for long haul; once that gets resolved,
11 because right now it's not resolved and what we're seeing
12 is that we're seeing a very low AECO price, which is
13 creating dispatch into Pacific Northwest, into Northern
14 California, more favorable than it has been historically.
15 But once that gets resolved, we expect more gas from
16 Western Canada to move to the premium East Coast market,
17 leaving less gas to move down to GT and into the Pacific
18 Northwest. So that TransCanada outcome as far as their
19 long haul rate moving gas from Western Canada to the East
20 Coast is probably a pretty important aspect of your
21 Canadian modeling.

22 MR. BRATHWAITE: Would you then expect --

23 COMMISSIONER PETERMAN: Let me just ask one
24 follow-up question to George, not being as familiar with
25 the details on this issue. So is that fix likely to

1 happen? Is it in the works?

2 MR. WAYNE: It's in the works right now, yeah.

3 COMMISSIONER PETERMAN: Okay, so that's something
4 that one could consider as a likely political --

5 MR. WAYNE: Likely. It's filed at the NEB. It's
6 filed at the National Energy Board.

7 MR. BRATHWAITE: So, George, we didn't expect
8 that Ruby will replace the gas that is lost on GTM?

9 MR. WAYNE: Right, which gets to my earlier
10 point, not just in the short term what I see now, but the
11 longer term, yeah, higher utilization on Ruby and
12 literally gas from EP&G to Transwestern, and you could
13 bring the gas up from the Desert Southwest, as well,
14 because of that fall-off of Canadian gas coming down GTN
15 into the Pacific Northwest.

16 DR. MEDLOCK: Well, just to sort of add something
17 to all of this, part of the reason GTN sort of has a
18 reinvigoration, if you will, is because, yes, you do see
19 growth in the shales, it does offset declines in the rest
20 of the Western Canadian sedimentary basin, but you don't
21 see TransCanada refill going west to east in the model
22 simply because you've got so much strong production
23 growth in the Marcellus and Eastern shale, which is
24 really pushing back on all that infrastructure. So
25 really, the only artery out is GTN, and that's exactly

1 why you're seeing what you're seeing in the model.

2 MR. WAYNE: Yeah, I see that in the model, but I
3 guess the question, well, pushing back is that plausible?
4 Because I think TransCanada will lower their rate, well,
5 they're going to move gas to that eastern market.

6 DR. MEDLOCK: Yeah, but you've got to remember --

7 COMMISSIONER PETERMAN: Well, TransCanada, you're
8 here. Any thoughts, TransCanada?

9 MR. BENNETT: No, see, I can't comment on the
10 Canadian pipe. I'm just not that close to it, I'm out of
11 the U.S. pipelines. Sorry.

12 COMMISSIONER PETERMAN: Sorry to cut you off
13 there, Dr. Medlock. Go ahead.

14 DR. MEDLOCK: No, that's okay. I mean, look,
15 you've got an issue when you think about competing on
16 TransCanada, I mean, it's not a short haul rate by any
17 stretch of the imagination and, yeah, I agree that we'll
18 try to maintain market share, but at some point it's a
19 losing battle because you're talking about a lot of
20 production on the Marcellus that is high in liquids. I
21 mean, they're talking about trying in the State of
22 Pennsylvania to expand NGL takeaway capacity and be able
23 to move all those liquids, and that's what is really
24 driving a lot of that production, which really lowers the
25 marginal cost of gas produced there. So you're talking

1 about trying to compete into a relatively low cost
2 environment and it's, you know, I'm basically just
3 describing why what you're seeing in the model is what
4 you're seeing, and I think there's a lot of information
5 on the ground that really supports the kinds of trends
6 that are turning up, so...

7 MR. WAYNE: The other aspect, you mentioned the
8 flipping in 2013 of the Topock to, I guess, Henry Hub
9 basis. I don't foresee that either, it has never
10 happened historically except maybe during the California
11 energy crisis, at least in our model, and we certainly
12 don't see that going forward. I mean, you look at the --
13 obviously there is some -- obviously more gas produced on
14 the east, but still the majority of your gas is being
15 produced in the western half of your market.
16 Incrementally going forward, getting more in the East,
17 but still not compared in an absolute basis. There's
18 still more gas being produced in the West, even with the
19 Marcellus growth. And then, what's going to absorb all
20 that growth in the East is you've got, obviously,
21 population growth, you've got the majority of your coal
22 conversions that are happening are in the Eastern
23 Interconnect, in the Southeast, that's where it's going
24 to absorb a lot of that gas. And then also they have,
25 particularly in the Southeast, Renewable Portfolio

1 Standards, unlike the West where you can look at wind
2 growth and development, you've got solar, geothermal, and
3 other renewable portfolios to be able to lean on, and to
4 be able to supplant demand, and you don't have that
5 luxury in the Southeast. So I guess my point is, even
6 though you may have some incrementally more gas being
7 developed in the East, it's going to be all absorbed and
8 they're going to still need to move a lot of the Western
9 gas to the Eastern market.

10 MR. BRATHWAITE: But you don't see any changes in
11 the differentials is what you're saying?

12 MR. WAYNE: No, we don't see a deck kind of
13 flipping of Topock to Henry -- Topock will remain below
14 Henry Hub.

15 MR. BRATHWAITE: Okay. Ken, did you have any
16 comments on that?

17 DR. MEDLOCK: I mean, the point he is making
18 about where the coal substitution is going to occur,
19 that's actually modeled, it's very explicit, actually, in
20 the modeling, so there's nothing that we haven't
21 accounted for on that front. In terms of load growth,
22 the largest projected load growth from just outright
23 population increases is in the West. The three fastest
24 growing states in the Union are actually in the West, so
25 you have to keep that in consideration when you're

1 thinking about total power gen demand, commercial and
2 residential demands, etc. So, anyway, it's a debate
3 worth having, but these are issues that we've tried to
4 capture in the model.

5 COMMISSIONER PETERMAN: I think George here
6 internally had a question - no, George or Greg? Tell me.

7 MR. KLATT: Greg Klatt for TransWestern.

8 COMMISSIONER PETERMAN: Yes. What was your
9 question, Greg?

10 MR. KLATT: Thank you, I'd just like to build off
11 of the discussion that we've been having, two points
12 first in terms of what Mr. Wayne said about Topock being
13 below Henry Hub, that's -- our analysis has that same
14 result going forward and also having Malin go up. And
15 the second thing is that -- a question, actually for
16 either Mr. Brathwaite or the doctor, is to what extent,
17 or did you take into account the variable transportation
18 costs in doing your modeling about which way gas will
19 flow and which lines or corridors will be utilized at
20 what levels?

21 MR. BRATHWAITE: Well, we do not presuppose the
22 utilization rates, everything is done through economic
23 dispatch.

24 MR. KLATT: Well, I understand that, but in terms
25 of modeling your economic dispatch, to what extent - or

1 did you take into account the actual transportation rates
2 on the different lines?

3 MR. BRATHWAITE: Well, we have differential rates
4 on all the lines.

5 DR. MEDLOCK: Yeah, the rates on the lines are
6 the FERC filed rates.

7 MR. BRATHWAITE: Yes.

8 DR. MEDLOCK: And there is also discounting
9 allowed so you can discount all the way down to basically
10 covering variable and demand charges. And when you're at
11 full capacity, you're running up against your max rate.

12 MR. KLATT: And just to clarify, did you use the
13 then current rates, the rates as of when you did the
14 modeling? Or --

15 DR. MEDLOCK: Yes.

16 MR. KLATT: Okay. Thank you.

17 MR. BRATHWAITE: Which I guess, Ken, we could say
18 rates as of January or late last year?

19 DR. MEDLOCK: It would have been late last year.

20 MR. BRATHWAITE: Yeah, okay. Okay, thank you,
21 everyone.

22 MR. TAVARES: Okay, thank you. That was a good
23 discussion. Our next speaker is Ross Miller. He is part
24 of the staff and he is going to be talking about the
25 California High and Low Demand Cases. Ross.

1 MR. BENNETT: Before you start, I'm actually
2 going to have to leave, I've got to catch a flight, but I
3 wanted to thank the Commission very much for having us.
4 We appreciate the opportunity to come before you and to
5 provide our thoughts and comments.

6 COMMISSIONER PETERMAN: Lee, thank you for your
7 participation and your comments, and look forward to
8 seeing you, or at least hearing from you on the phone at
9 our next workshop.

10 MR. BENNETT: Great, thank you.

11 MR. WAYNE: And Commissioner Peterman, I also
12 have to leave, but I do appreciate the opportunity, El
13 Paso appreciates the opportunity, and I think this is a
14 great forum and a great start to you all building a solid
15 foundation.

16 COMMISSIONER PETERMAN: Well, George, thank you
17 once again and I appreciate your detailed review of the
18 assumptions, and I think you've provided some good
19 insights that we'll take back and, if you have any
20 comments on any of the other sections, please don't
21 hesitate to share them with us. Thank you.

22 MR. WAYNE: Thank you.

23 MR. TAVARES: Just for the record, George gave me
24 a comparison of the outputs -- our outputs and their
25 outputs, and he's going to send me an electronic version

1 of this comparison for everybody to see.

2 COMMISSIONER PETERMAN: Well, thank you, George.
3 Then you really can go now.

4 MR. MILLER: This is the point of the staff
5 presentation that gets away from any expertise in the
6 natural gas systems. I'm Ross Miller and I work in the
7 Electricity Analysis Office, so I'm just disclosing I'm
8 not an expert on natural gas. My role has been more
9 focused on the overall purpose, scope and design of the
10 Gas Market Assessment, in general and hopefully
11 explaining how that effort can actually be useful and
12 maybe even used.

13 My presentation is briefly going to discuss the
14 organizing questions, the framework for providing useful
15 information and the key drivers of gas demand that we
16 focused on in the two cases that I'll be discussing. I'm
17 going to describe those cases which were specifically to
18 explore the effects of changing Reference Case
19 assumptions about California gas demand, to make it
20 either higher or lower than the Reference Case. And then
21 I'll discuss the World Gas Trade Model and I'll actually
22 spend more time on what we're calling Post-Processing
23 Results for all the cases, including the National cases
24 that Leon and Ken discussed earlier.

25 In Commissioner Peterman's and Ruben's opening

1 comments, you both touched on the issues this slide
2 discusses. I'll elaborate a bit more because they
3 provide both the rationale for choosing the cases that we
4 built and are key to understanding how the results might
5 be useful.

6 So obviously the real world activities that the
7 model seeks to represent are fundamentally characterized
8 by a high complexity, many alternative options for
9 actions which this presentation will focus on those that
10 go on within the electric generation system and affect
11 gas demand by that sector. And, of course, deep
12 uncertainty about all of these interactions. And not
13 only do these affect the gas market activities, but also
14 electric generation and other related energy markets like
15 transportation.

16 So the bottom line of all that is our estimates
17 really have to be taken as conditional estimates. We've
18 had a number of people already comment that they would
19 expect to see something different and, as Ken tried to
20 do, if you trace that back, it might be because they have
21 a different input assumption than what we used, and
22 that's basically how models work. If they are all
23 conditional estimates that you really have to measure not
24 only how the models are working, but how different are
25 input assumptions, and it's those two things together

1 that you start to understand why the output is different.

2 Even if we could make accurate predictions of the
3 future market -- I'm sorry -- assuming that you can't
4 make an accurate prediction with any model, as
5 Commissioner Peterman started, we still have to make some
6 assumptions about the future when we are making specific
7 policy decisions, whether it is a decision about how
8 cost-effective an energy efficiency program might be,
9 which assumes making some presumption about the avoided
10 cost which in California since natural gas is the
11 marginal supply to electricity will imply some assumption
12 about natural gas prices. So what you do, that's why
13 we're running models. Running models is a good way to
14 understand how the different market outcomes could occur
15 in the future given different conditions.

16 I'm going to back up one more. So we could
17 present one case. The danger there is that it might be
18 either too rosy or too pessimistic view of the world, and
19 basically you'd be introducing one-sided bias. So the
20 whole strategy of producing a number of cases that have
21 plausible input assumptions is so you can cover against
22 that bias. Basically, I mean, even if you could predict
23 what case would be most likely to happen, other cases
24 could still happen and they could have negative
25 consequences, so you would still want to know what those

1 might be. I mean, if you're playing craps, you know that
2 rolling a seven is the most likely outcome, but I don't
3 think that everyone goes to a casino every month and bets
4 their whole paycheck on one roll of the dice. I mean,
5 it's basically that straightforward. So this shifts the
6 focus of our discussion to gaining a better understanding
7 of what the underlying drivers are and the uncertainties
8 that are inherent in our trying to predict what the
9 future states of those drivers will be, and then that
10 working through our understanding of the relationships in
11 the gas market that are imbedded in the model to get the
12 results. So having a better understanding of all of this
13 is what allows us to make more robust decisions, which
14 are basically decisions that end up with satisfactory
15 consequences over a wider range of future conditions that
16 actually end up happening.

17 So these questions were in Leon's presentation.
18 These are the organizing questions, why we structured the
19 cases the way we did. And after writing this slide, I
20 realized there is kind of an inherent bias, even in the
21 way this slide is constructed, the way I've basically had
22 the implied assumption that high gas prices and high gas
23 demand lead to vulnerabilities, whereas low gas prices
24 and low gas demand lead to opportunities. Depending on
25 what metrics you're using, low gas prices and low gas

1 demand could lead you to vulnerabilities; for example, if
2 your analysis is excluding externalities and public
3 goods, then you may come to the wrong conclusion about
4 what's an opportunity and what's a vulnerability.

5 But the high and low approach is basically to
6 give the decision maker the information so they can
7 consider, "Well, what if we make this decision assuming
8 gas prices are high?" They turn out to be low. What are
9 the consequences of that? Or, vice versa. Or, "What if
10 we make a decision assuming gas demand will be high and
11 it turns out to be low?" What are the consequences of
12 that? And vice versa. So basically we want to be aware
13 of what the potential consequences could be of our
14 particular use in a decision of any of these estimates or
15 forecasts, whether it's a gas price or a demand level.
16 So we're really not stuck trying to figure out what is
17 the most likely market outcome. We actually have the
18 option to think about what regret might I have if I use
19 one number versus another, which is a defensible approach
20 if no one can defend one of the forecasts being more
21 likely than any other to actually come true. In a lot of
22 cases, that's the position we're in: we can perhaps
23 narrow a range, but we can't get rid of all the
24 uncertainty.

25 So really, the question we end up asking

1 ourselves is, you know, given the information all these
2 studies provide about potential outcomes, what really is
3 the most prudent number or quantity for me to use and
4 what are the potential consequences of my using that?
5 And so, I think it follows that different users of these
6 forecasts, besides having different purposes which lead
7 to different potential consequences, they all have
8 different levels of risk tolerance for the risks inherent
9 in their use of the numbers, so you can probably justify
10 different people using different forecasts for what
11 they're doing.

12 Basically, these are the drivers that we focused
13 on in the California High and Low Gas Demand cases.
14 Economic Condition is a key driver. The rest were
15 largely focused on the policy drivers that are basically
16 aimed at the electric generation, demand, resource mix,
17 or efficiency of generation. Everything from energy
18 efficiency programs, both for electricity and gas,
19 renewable generation programs from the RPS to distributed
20 generation programs, combined heat and power, all act to
21 decrease electric generation gas demand. On the other
22 side, you've got transportation, electrification,
23 shutdowns of coal and nuclear power generation, all act
24 to increase electric generation gas demand. And of
25 course, those all interact and some run counter to each

1 other which, besides trying to make an estimate of the
2 future state of any of those individually is difficult
3 and fraught with uncertainty, trying to figure out the
4 ultimate outcome of the interactions of all these things
5 just makes it more complicated.

6 I'm going to quickly go over the input assumption
7 changes we made to the Reference Case in order to get the
8 High California Gas Demand case. The changes are
9 dominated by an increase in gas-fired electric
10 generation, either to meet higher electricity demand
11 growth, to replace electricity from our state's two
12 nuclear power plants, which we assumed were not
13 relicensed, to make up for the assumption of a slowing
14 renewable generation development, and to serve a slight
15 increase in electric vehicle charging. We also had, not
16 related to electric generation, but we also added in some
17 direct natural gas transportation to this case.

18 Okay, I'm going to note here, but I'm going to
19 wait until later in the slide show that we made an error
20 in execution of these changes when creating this case, so
21 the results that are in the Outlook report and in this
22 presentation are the results of changes that are actually
23 different than this, and I'm going to explain what the
24 difference is. And you know, not to keep you in
25 suspense, it's not a major change, the gas demand for

1 this case, if we had executed as described here and in
2 the report, would be about five percent higher in 2017,
3 eight percent higher in 2022, and about 13 percent higher
4 in 2030. That doesn't sound like a lot, but it's a big
5 system, so when later I talk about the differences
6 between the cases, you'll see the numbers get to be a
7 little bit bigger. And, well, from now on for reasons
8 I'll make clear later, I'm going to refer to this error
9 as a learning experience. [Laughter] I told you I
10 hadn't worked in gas before, so I've learned a lot in
11 addition to this little learning experience.

12 In the Low California Gas Demand case, we took a
13 similar approach. The assumption changes in this case
14 are really dominated by accelerating renewable
15 generation, at both central station and distributed
16 generation facilities, which generally displace gas-fired
17 generation. I don't think I listed -- oh, I list it here
18 -- there was a slight decrease in the --- I should make a
19 distinction here, in this model the overall rate of
20 growth of California electric demand is not the GDP,
21 which affects the whole economy, this is a sub-estimate,
22 which we had built into the model, where we can mimic
23 either additional energy efficiency, or economic growth
24 affecting demand. So you can think of this as a slight
25 change to the amount of energy efficiency, without

1 expressly labeling it that way.

2 Well, probably some of you are wondering if we
3 had a learning experience with this case, too, and I'll
4 have to say we did, but it was a much smaller effect and
5 it really doesn't affect the results anymore than about
6 one percent, so I'm not going to complicate the
7 presentation by providing corrected numbers for this
8 case. So I guess we didn't learn as much on that one.

9 Now, this slide is labeled Input Assumptions, so
10 I wanted to make clear that that's what it is. The
11 shaded area are the exogenous input assumptions that we
12 made about electric generation in California, and those
13 fed into the econometric analysis, which is again still
14 not in the World Gas Trade Model. There's an econometric
15 analysis that estimates what the gas demand for electric
16 generation is, and those were the unshaded numbers at the
17 bottom of each array for 2017, 2022, and 2030. So the
18 colored areas are input assumptions for the econometric
19 modeling, the uncolored area is the output of that, and
20 that is the input to the World Gas Trade Model. And
21 that, I think the term has already been used before, that
22 is called the Reference Quantity of Demand because, once
23 you put that into the World Gas Trade Model, the
24 equilibrium model will solve for a final demand at a
25 price of equilibrium, showing the effect of price

1 elasticity of demand, so the final demands end up being
2 different than these inputs.

3 So just to give you an idea, at this stage of the
4 assumptions, the percentages I gave you before still
5 apply, and it only really applies to the middle column,
6 the High California Gas Demand. The 2022 figures for Gas
7 Demand should be about eight percent higher, and the 2030
8 figures should be about 13 percent higher. Now, the
9 reason we didn't re-do all these slides is we would have
10 to re-run the World Gas Trade Model to get the actual
11 corrected output for the High Gas Demand case and we
12 didn't have time to do that, so later I will be giving an
13 estimate of how those final demands and the other metrics
14 that are derivative of that have changed, that's all
15 based on this estimate and not the model output.

16 Effectively, what we ended up doing and why I'm
17 calling this a "learning experience," is we kept track of
18 the story that went along with making our changes to
19 create a case; well, it turns out that the High Gas
20 Demand case, we made a change that was effectively the
21 same as just removing the two nuclear power plants, not
22 the other things we wanted to do. We made about 60
23 percent of the change we had intended and because we
24 contract through that, effectively what we end up with is
25 another case, and it ends up being an incremental

1 sensitivity case which actually turns out to be useful,
2 as long as we can imagine what the real output would look
3 like for the High Gas Demand case, which I'll give you a
4 hand with this handy laser pointer.

5 So this is a diagram of the output of the World
6 Gas Trade Model for Gas Demand in California and for all
7 the cases. So this is the case now that actually
8 reflects just taking out to two of the nuclear power
9 plants. And so the case that matches the description of
10 the high gas demand case would be up here, so that would
11 be the outlier as far as gas demand.

12 Now, this is a table we put together that
13 basically creates some very rough estimate metrics other
14 than gas demand -- I'm going to go back to this -- I told
15 you I'm not a gas expert, so I look at this and I think
16 trillion cubic feet, and it's just a big number to me,
17 I'm not really sure, I know it's more, I know it's less,
18 so I'm trying to provide some extra sense of the
19 significance of these numbers, so we just decided to come
20 up with some other metrics that are either policy
21 relevant or more intuitive to people, I guess not that I
22 have anymore sense of what it's like to have millions of
23 dollars, but I deal with that a lot more than I deal with
24 trillion cubic feet, so I think I have a little better
25 sense.

1 So again, in the column for High Gas Demand,
2 those numbers would all be slightly different. The gas
3 demand numbers would all be those percentages -- five,
4 eight percent, and 13 percent higher, and so would all
5 the effects, it's basically multiplicative. Where you
6 get a little larger sense of the impact of this change is
7 where you just look at the effect it had on the
8 differences among cases, which I'll get to in later
9 slides, but this is fairly straightforward. Another
10 thing I wanted to point out is it didn't change the
11 relative position of the cases we intended, this high
12 case is still the outlier, we just now have inserted an
13 intermediate sensitivity case.

14 The metrics that we included on here were very
15 simple, we just took the gas demand, multiplied that by a
16 weighted cost for electric generation to come up with a
17 cost for gas demand by electric generation, and the cost
18 came out of the associated case, so since the price is an
19 outcome of the case, that's the one relationship in this
20 table that is not completely linear. You would have to
21 re-run the model to get the associated electric
22 generation price to multiply here. The carbon emissions,
23 the CO₂ emissions from the combustion of this gas, is
24 simply an emission factor times the quantity of gas. And
25 the CO₂ allowance cost is that emission quantity times --

1 basically what we selected was the reserve price or floor
2 price from the AB 32 Cap-and-Trade Program that is
3 specified in the Initial Statement of Reasons. And that
4 would be at least as much as you could say is opportunity
5 costs of those emissions; you might end up paying more if
6 the dollar per ton auction cost of a CO₂ allowance is
7 higher than what is assumed there, but at least this
8 would be a floor.

9 Another thing I want to say about this is, if you
10 have the question of what would be the best outcome in
11 all these cases, this table does not give you the answer
12 to that. If you think of that question being answered by
13 a thousand-piece jigsaw puzzle, this only provides about
14 10 pieces, okay, so these are just selected metrics of
15 change across these cases, it's not meant to be a
16 comprehensive trade-off analysis, it doesn't tell you
17 what the bottom line is. You know, for example, to get
18 the outcome of the high gas price case, you know, someone
19 is going to have to replace 50,000 GW of coal and that's
20 going to cost money, and this analysis says nothing about
21 that. So we're not trying to measure all attributes and
22 do a trade-off. This is basically just to contribute to
23 that overall "thought experiment," I'll call it.

24 So the next four slides are just going to
25 basically focus on the differences between the numbers on

1 this chart, just to make it a little clearer. And so
2 this High Gas Demand case is actually going to be around
3 here, and this is essentially taking out the two nuclear
4 power plants.

5 Now, here is where I mention, if you do the math,
6 the difference between the actual high as described in
7 the report, High Gas Demand case, is really about 2.38,
8 so here it's off the chart, so I didn't mean to minimize
9 the characterization of this learning experience with
10 five, eight, and 13 percent, because here it's basically
11 -- this increases 21 percent from the Reference Case, the
12 case that we described is about a 36 percent increase
13 compared to the Reference Case.

14 So this, as I mentioned, it just shows you the
15 magnitude of the dollars you're talking about on an
16 annual basis if you were paying for those emissions at
17 the reserve price. And to correct the High Gas Demand
18 case, that would be, I think, about \$1.5 billion in 2030,
19 so the numbers are not insignificant.

20 COMMISSIONER PETERMAN: Ross, can I interject and
21 ask a quick question? You can find it in both graphics,
22 but with Slide 11, with the Low California Gas Demand,
23 what is the percent different from the Reference Case?
24 I'm trying to get a scale of it, the difference between
25 the Low case and the Reference vs. the High case and the

1 Reference.

2 MR. MILLER: Oh --

3 COMMISSIONER PETERMAN: I think you said the High
4 case was like 36 percent once we do the revised analysis?

5 MR. MILLER: That is basically about 25 percent.

6 COMMISSIONER PETERMAN: Okay. So it seems like
7 also with the next slide, as well, that some economic
8 value, the \$1.5 billion difference in the Reference case
9 and the High case is larger than --

10 MR. MILLER: That's right.

11 COMMISSIONER PETERMAN: And is that the trend
12 that we see, this wider variation between the High case
13 and the Reference vs. the Reference and the Low?

14 MR. MILLER: Right. Yeah, it's not asymmetrical.

15 COMMISSIONER PETERMAN: Okay.

16 MR. MILLER: And we didn't really construct the
17 cases to be purposely symmetrical and a reference was
18 made to EIA cases. I think the last EIA Annual Energy
19 Outlook had 68 cases, and that's to underscore Ken's
20 point, is to really compare the significance of
21 differences in output across other people's work, you
22 have to not only know how the modeling differs, but you
23 also have to really do a very point-to-point comparison
24 of all the input assumptions, especially since so many
25 people are doing so many different cases. But that's

1 where the better understanding of what's going on really
2 comes from. And it does take time, as Ken suggested.

3 I can stop for questions here. I have two more
4 slides that are basically about the last chapter on End-
5 Use Prices and the discussion is going to be similar to
6 this, it's basically an illustrative presentation to get
7 a sense of the magnitude of uncertainties about end-use
8 prices.

9 So this, if you notice, we don't even have
10 identified a utility here; the main point of this slide
11 is just to show that there is a significant difference in
12 end-use gas price, depending on which sector you are, and
13 the reason is it is cost of service based and the
14 residential sector is the most expensive to serve, so
15 it's going to have significant transportation and
16 distribution costs that get added to the City Gate Price,
17 which is basically the commodity and the cost of
18 transportation to that point in order to fully recover
19 all of the costs of that service. Commercial is the next
20 most expensive. And Industrial and Power Gen, because
21 they accept their service fairly close to the backbone,
22 are not paying as much in incremental distribution cost
23 because it doesn't cost that much incrementally to serve
24 them.

25 Now, obviously -- well, it's not obvious since I

1 didn't tell you or label this -- this is a Reference Case
2 City Gate price. Since we have different cases, you can
3 come up with a different end use price for each sector,
4 for each case, and we did that and we posted that on the
5 website, and we did that for each utility, and it's there
6 for people to look at and inspect. But one thing we want
7 to say about it is we took current estimates of the
8 transportation costs and did not make any attempt
9 whatsoever to assess what they might be going forward in
10 a comprehensive way, and then put out all those datasets.
11 So if you think of this as just -- this is another one of
12 those reference points. What we did in the rest of the
13 chapter was just to talk about, while there are sources
14 of uncertainty about what transportation distributions
15 costs could be, and that may be of less concern to the
16 Industrial and Power Gen sectors because it's not really
17 that big an additional cost to their end-use gas price,
18 but for Commercial and Residential customers, it's
19 something to be interested in. So we basically
20 identified just three areas where there is some rough
21 assessment of what the uncertainty about the future value
22 of these costs might be and one of them was the capital
23 investment that might be required for pipeline
24 inspection, repair, or replacement, for either public
25 safety or environmental reasons. In the report, we

1 mention that either concerns about the pipeline integrity
2 or environmental contamination of certain pipelines,
3 requiring them to be replaced, all create a possibility
4 that there could be some going forward costs that
5 wouldn't be included in the existing rates.

6 We just did a "what if" analysis and I think we
7 used PG&E's system, and with the billion dollars of
8 capital investment, that ended up being about an eight
9 percent increase in just the transportation cost
10 component. So, if you're looking at a residential
11 customer where that is only half of their end-use rate,
12 that would be a three or four percent increase in their
13 end-use rate. And we made no attempt to figure out how
14 many hundreds of millions or billions of dollars might be
15 needed to be spent in the future on anyone's pipeline
16 system.

17 The other -- there was a debate about the Public
18 Purpose Program Surcharge. That turns out to be a fairly
19 hefty chunk of the residential and commercial, so we
20 thought that was worth looking at, and that was about 11
21 percent of the residential transportation distribution
22 cost and it was a much higher percentage of the
23 industrial, actually.

24 And the last thing we looked at is basically just
25 again looking at the cost of CO₂ allowances since

1 ultimately those costs have to be recovered from end-
2 users. And this was, again, at the minimum floor price,
3 this was about a five to 10 percent of City Gate prices,
4 well, five percent in 2012 and about 10 percent in 2030,
5 just to give you an idea of the magnitude.

6 I think I'll end it here and if there are any
7 questions, I can entertain them, or -- we've lost Ivin.

8 COMMISSIONER PETERMAN: Ross, I have a follow-up
9 question. Is this the first time in the IEPR, or at
10 least relative to 2009, that we've modeled the forecast
11 End-Use Gas Prices?

12 MR. MILLER: No.

13 COMMISSIONER PETERMAN: This is not, okay. I
14 just remember we had some discussion around the value of
15 getting feedback about this analysis and how can it be
16 utilized going forward, and so I particularly would
17 appreciate Scott's feedback on this and some of the
18 assumptions raised and the uncertainties identified.

19 MR. WILDER: Well, I have a related question.
20 Scott Wilder, Southern California Gas. Ross, I guess I'm
21 not quite sure, but in your California High and Low
22 Demand scenarios, are there differences in gas price
23 assumptions?

24 MR. MILLER: In the High and Low Gas?

25 MR. WILDER: Yeah, the High and Low Gas Demand --

1 MR. MILLER: Not in -- each case has an input
2 reference quantity price assumption for oil, for gas, for
3 coal, and even electricity. But each of those cases ends
4 up having its own final gas price. So if the question
5 is, is it significantly different than the other cases,
6 it's not significantly different than the reference case
7 because moving California Demand really isn't a big
8 enough driver of national prices to get much of a
9 movement.

10 MR. WILDER: Okay, I was asking more related to
11 the input assumptions, if the inputs assumed the same gas
12 prices for the High and Low.

13 MR. MILLER: Yes.

14 COMMISSIONER PETERMAN: Why do you ask?

15 MR. WILDER: Well, I'll go ahead and make a
16 comment, it's probably related to both the national that
17 we passed with Leon and the California would have an
18 effect. Kind of reinforcing what both George and Mia
19 said in a statistical way, looking out at least a decade
20 or more and assuming such a narrow range, I did not do
21 this for the Topock California Border Price, but I did go
22 back when I looked at this last week and just looked a
23 little bit statistically for the Henry Hub National
24 Price, and if you go back to even just the past 10 years,
25 2001, you end up looking at real 2010 prices and the

1 volatility in the last decade, and you end up with a
2 standard deviation that is over \$2.00 per million Btu.
3 And if we just, for instance, go out 10 years to, say,
4 2022, we have kind of a national case, and I think it
5 would apply to California, as well, where you can add say
6 \$.20 per million Btu for transportation, where we have a
7 Reference Case that is in 2010 dollars out in 2022 of
8 roughly \$5.50, and a High-Low variation of only about
9 \$.50 on either side, so we've got a range of about a
10 dollar plus or minus \$.50. Well, if you took even one
11 standard deviation, which statistically would exclude
12 about a third of the possibilities for normal
13 distribution, instead of \$.50 on each side, you're
14 talking \$2.00 on each side, so suddenly you're talking a
15 range of instead of five to six, you're talking a range
16 of about \$3.50 to \$7.50. And in a real life case, you
17 know, in the past 10 years, four out of the 10 years have
18 seen -- and I'm talking annual average prices here --
19 four out of the 10 years have seen changes from the
20 previous year of more than \$2.00 a million Btu. And
21 where this comes in to California demand is, if you just
22 take the price elasticity, we've talked a lot about
23 electric generation here where it may not be so
24 important, but in the case of residential and commercial
25 demand, where you've got certainly a lot more California

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1 residents involved, you know, instead of talking about
2 \$.50 on roughly \$5.00, instead of a 10 percent variation
3 in price here, you're suddenly talking about a 40 percent
4 variation in price year to year, and, well, Commissioner
5 Peterman, you said earlier in the day that one of the
6 reasons for the scenarios is the Commission doesn't want
7 to be surprised, and I would emphasize I think there is a
8 real need to widen the scope of these ranges and the
9 scenarios, particularly with the price because it affects
10 not only the price, but it also affects the California
11 demand and commercial, residential elasticity, you know,
12 if you assume it's maybe .1, .2, you talk about a 40
13 percent change in annual prices, well, you're talking
14 about a six to eight percent change in demand from year
15 to year that is simply driven by price.

16 COMMISSIONER PETERMAN: Yeah, please Leon, come
17 up. And thank you, Scott, for those comments. I think
18 those are in line with what we heard from George and a
19 bit from Mia, as well, and we'll make sure we take that
20 into consideration. Leon was going to make a --

21 MR. BRATHWAITE: Yeah -- I'm sorry, I did not get
22 the name. Scott, thank you. Scott, I do not doubt your
23 analysis, okay? But one of the things that I will say
24 that will really mitigate against having a wide range,
25 and you were right, probably a wider range would be

1 probably more duplicative or more representative of what
2 we have seen in the past, I would not disagree under any
3 circumstances. But if you look at the cases that we've
4 presented, nearly every one of those cases, and you look
5 at the supply cost curve which is probably the biggest
6 driver in our model, they all have that big long flat
7 portion of the curve, which was one of the things that
8 Mia pointed out. So what I think is happening here, so
9 why we are not seeing a wider range, you know, we could
10 probably make assumptions that will produce one, but the
11 thing that has happened here is that shale is coming on
12 at such a strong level in nearly all the cases that we've
13 seen that it's just difficult to get that wide range that
14 you probably would expect. And like I said, maybe we
15 could go back and, with the permission of the other
16 Commissioners and stuff, we could turn off some more of
17 the shales, or do some other things and stuff, and widen
18 the range. But I think the underlying thing is that
19 shale is such a big deal right now, it's just now in the
20 range to what we are seeing there. Thank you.

21 COMMISSIONER PETERMAN: Can I ask a follow-up
22 question on that and the supply cost curve? So, is the
23 way in which shale is affecting or entering the results
24 that there is such a large flat portion of that curve
25 because there is shale built into the model, lower cost

1 shale? Or that it is not being --

2 MR. BRATHWAITE: Yes, shale is added into that
3 flat supply cost curve. If you look in our presentation
4 and you look at the 2007 supply cost curve, if you
5 remember, it got pretty steep pretty quick, but then once
6 we come to 2011, where you have a lot more shale and all
7 that kind of stuff, that curve just got flat and didn't
8 run out until it got to I think it was 600 or 700 TcF
9 before you started to see that upward swing.

10 COMMISSIONER PETERMAN: And Scott and Mia, have
11 you come across other supply cost curves that includes
12 that shale, but don't have such a flat part of the curve
13 in the lower quantities?

14 MS. VU: As I mentioned before, the gas industry
15 is something that is very hard to find those information
16 on the cost side, but I do believe that, even though we
17 have a lot of shale resources, there are a lot of
18 uncertainties on that cost. So if we can capture some
19 kind of the uncertainty around that, that may increase
20 the variation on the outcomes on the price. Because I
21 see the way you construct those cases are very deliberate
22 and very thoughtful, so the scenarios are all right.
23 It's the assumptions that go into the model and it comes
24 out to be the result of the model. Definitely long-term,
25 shale will give us reasonable prices compared to what we

1 experience in the last decade, but to me there is still a
2 lot of unknowns.

3 COMMISSIONER PETERMAN: Fair enough, so that
4 could be the long-run, but there is some opportunity to
5 think about a more steep curve, or at least there are
6 plausible futures with a steeper curve in the near term
7 that we can consider. Dr. Medlock?

8 DR. MEDLOCK: Yeah, I'd like to interject
9 something. I don't know if it's possible to bring my
10 presentation back up because I can address something that
11 is pretty germane to this whole discussion. I presented
12 a slide --

13 COMMISSIONER PETERMAN: Give us a minute to try
14 to do that. Go slower.

15 DR. MEDLOCK: No problem, no problem.

16 MS. VU: It's at page 16 that you talk about?

17 DR. MEDLOCK: I can't remember the slide number,
18 but let's just go up, it might be around there, yeah.
19 Oh, it's going to be earlier in the presentation. It's
20 actually the Index of Costs against the Index of Oil
21 Price, so go up to -- I think Mia said slide 16 --
22 because this isn't the right one to look at. That's it
23 right there, yeah.

24 All right, so forget about the blue line right
25 now and just focus on the red and the green line. These

1 are actually -- I mean, this is real data, right? This
2 is the actual cost by FIC Code in the case of the green
3 line for the oil and gas mining sector, so that's all
4 upstream activities, and the red line is the actual real
5 costs of well development as reported to EIA of operators
6 in the Lower 48. And if you just look at the last 10
7 years, at the variation in that cost, so just go from
8 1999 to 2009, you can see at the low point, which would
9 have been back in 2000, '99 to 2000, up to the high point
10 which would have been 2008, you saw cost inflation, so
11 that scale in terms of what happens to cost increased by
12 a factor of two and a half, okay? So if you look at that
13 and you begin to understand, you know, this is why I
14 brought up the point about, you know, we talk about
15 break-even cost and the cost of the environment, if you
16 want to think about the variability, the potential
17 variability in the cost environment, right, that's a
18 different sort of exercise and there is certainly the
19 capability to run scenarios around cyclical behavior and
20 the cost environment. In particular, you could run a
21 case in which you sort of assume a high cost environment
22 in which you might assume costs look something like they
23 did in 2008, for example, going forward. That is going
24 to be sure to give you very high prices. And you could
25 also run a case where you assume the cost environment is

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1 relatively low like it was in the '90s, that is going to
2 be sure to give you very low prices. If I were to do
3 that, you would actually get a range of outcomes that is
4 going to match history because that's exactly what we're
5 looking at here, okay? So one of the big uncertainties,
6 one of the big drivers in sort of determining sort of the
7 vertical position, the height of the supply curve, is
8 exactly what you assume about this. So if we wanted to
9 do scenarios where we wanted to vary that supply cost
10 sort of environment, that is certainly something that
11 could be done, it's just not something that we addressed
12 at all in the cases that we've done so far.

13 COMMISSIONER PETERMAN: Dr. Medlock, in the
14 context of this graph and this discussion, then, what is
15 done to construct the supply curve now? It is to do
16 what, to take the average or...?

17 DR. MEDLOCK: No, no, what you would do -- in the
18 context of this, all the cost curves are actually
19 developed based on data that has sort of a real vintage
20 2005 kind of year, okay? So if you're looking at 2008
21 data, you would actually have to deflate the cost data so
22 that you could get a real well development cost data
23 point in 2005 dollars, right?

24 So if you want to maybe scroll back down to Slide
25 42, or whatever it was, if we wanted to go from, say, a

1 2005 to a 2008 cost environment, effectively what we
2 would be doing is taking this North American curve and
3 shifting it vertically, okay? Because one of the things
4 that happens in the real world is this curve is actually
5 going to have some uncertainty around it. In other
6 words, it's going to move from year to year up and down.

7 The horizontal dimension is pretty much defined
8 by whatever the resource availability is and what
9 technology is. But the vertical dimension is something
10 that we can slide, that's just not something that we've
11 done in the case of these scenarios because what we're
12 trying to do is isolate or model things in a particular
13 sort of cost environment, a particular real price
14 environment, and so typically what we would do is we
15 would take a stand on where the supply curve sits. And
16 that's actually why I showed that slide before, right,
17 about the cost environment.

18 Obviously, this is a huge uncertainty, right? I
19 mean, as I mentioned, the data that I showed you in that
20 previous slide goes all the way back into the 1950's and
21 you can see the same thing happen. Any time there is a
22 run up in energy prices, costs are chasing them. And so
23 that's certainly going to be the case going forward, as
24 well. In general, though, what we projected is sort of a
25 mid-trend in terms of the cost environment. There is

1 certainly going to be times when costs are lower, so
2 prices will be lower, so certainly there will be times
3 when costs are higher and prices are going to be higher.

4 MS. VU: My question to you is can you build the
5 variability around the horizontal curve as a range of --
6 horizontal part -- as some range, give it some range and
7 certainty there?

8 DR. MEDLOCK: Well, you can base it on the data,
9 you could do a look-back and base that sort of
10 uncertainty on, you know, what we know about history.
11 The trouble is the resource set is different now. You
12 know, those costs and the drivers of cost were largely
13 focused on non-shale unconventional and conventional gas
14 developments. Now, we're talking about a massive amount
15 of shale gas that has sort of different characteristics
16 when it comes to upstream development. So you could do
17 that, but it's going to be, at best, a second best
18 approximation. That's why, I mean, I told you we have a
19 Well Economics Model, when you look at what is called the
20 break-even costs that are in one of the slides earlier,
21 you actually see in some of the larger shales there is a
22 tiering of the resource. That is because we could
23 actually identify type wells based on existing data to
24 date, right? Where we can actually see well performance
25 metrics and we know what it costs for access, we know

1 what it costs to actually drill a well, what it costs to
2 complete a well, what it costs to bring in the frack
3 crews, so on and so forth. So we can actually come up
4 with numbers that are reasonable estimates.

5 You know, going forward, I would actually argue
6 that the risk in terms of what is going to happen to this
7 cost curve is more on the down side than the up side
8 simply because developers are still learning so much
9 about this particular play that, as they move forward,
10 and that's why I drew attention to my previous remarks to
11 the case of the Barnett where there has been over 14,000
12 wells drilled and developers are actually able now to
13 employ fewer rigs on the play and they're still producing
14 every bit as much as they did three years ago. It's
15 because there is a major learning by doing component in
16 this particular play. So, you know, just to sort of I
17 guess tie this up, one of the things that could be done
18 is we could model high cost environment, we could model
19 low cost environment, but you have to recognize if you're
20 going to take that stand, you have to assume that,
21 because this is a non-stochastic model, you have to
22 assume you're in that high cost environment for the
23 entire model time horizon, right? Then you have to
24 assume you're in that low cost environment for the entire
25 model time horizon and you're going to get very wide

1 outcomes in terms of the actual prices that you generate
2 in the forecast.

3 MR. RHYNE: So this is Ivin Rhyne. And this is
4 actually a really good point for me to make a statement
5 that perhaps has been inferred here throughout this
6 conversation, but probably needs to be done more
7 explicitly here, is that the questions we're able to
8 answer with regard to natural gas prices and quantities,
9 are to some extent limited by the tools and the
10 assumptions that we used. In this case, we're using a
11 tool that is a model that establishes an annual average
12 equilibrium price and quantity for various regions and
13 various suppliers. And in doing so, it washes out that
14 short-term variability and, as Ken just kind of
15 mentioned, this is a non-stochastic model, which kind of
16 in English means you don't see that random variation in
17 the underlying effects. And so, if we wanted to ask and
18 answer questions with regard to short-term variability of
19 prices, and its effects on demand, and they are certainly
20 non-trivial, especially in times as these where we can
21 see that you have short-term both price spikes and price
22 dips. That would require a different approach, although
23 it would certainly draw on a lot of the underlying work
24 that has gone into this, and so it wouldn't be completely
25 independent of this, but it would require a slightly

1 different approach, and so the staff here are very
2 interested in those kinds of questions, but I don't think
3 it's kind of in our purview at this point to attempt to
4 promise that we could give you that kind of analysis with
5 this particular tool, or at this particular date.

6 COMMISSIONER PETERMAN: Ivin, thank you for that
7 additional background. I would ask for staff to consider
8 the comments that have been raised and, at the minimum in
9 the final report in the Executive Summary, just to
10 identify some of these issues again because this
11 conversation in the last few minutes has been very
12 helpful to me, including pointing out that we do lose
13 some of the short-term variability or observation of that
14 when doing this analysis, and as Dr. Medlock pointed out,
15 if one was to answer a particular question like that, you
16 would need to do X, Y, Z, because I think that would
17 allow one to become more comfortable with what our
18 estimates are showing and what they can and cannot do,
19 and that was great additional information you shared.
20 Thanks.

21 MR. RHYNE: Thank you.

22 CHAIRMAN WEISENMILLER: Another question I had on
23 the retail rate side is, do we know what is in the
24 balancing accounts for the utilities on the gas side? I
25 assume for PG&E, it is getting significant, I'm not sure

1 about Sempra, in terms of under-collections.

2 MR. MILLER: Well, I claim the Fifth, so if
3 anyone else wants to answer.

4 CHAIRMAN WEISENMILLER: Yeah, do you know?

5 MR. WILDER: I'm not sure for SoCalGas.

6 CHAIRMAN WEISENMILLER: For PG&E?

7 MS. VU: I don't know about that.

8 CHAIRMAN WEISENMILLER: Okay. Yes?

9 MS. VU: I could ask about that.

10 CHAIRMAN WEISENMILLER: That would be good.

11 MR. COWDEN: I think another thing to focus on --
12 hi, Bob Cowden, PG&E. I think another thing to focus on
13 that was kind of at the end of Ross' slides is we made a
14 filing in August on kind of all the capital improvements
15 we have to make on our system, and in the final it
16 outlines over the next four years what the growth in our
17 revenue requirement is going to be, so there is
18 information that there could be used to I guess either do
19 another scenario or do an estimate of what the rate
20 increase could be, subject to however that gets run
21 through the CPUC process.

22 CHAIRMAN WEISENMILLER: Yeah, that would be
23 helpful just to know in the past forecasting retail rates
24 that you have to look at the balancing accounts and, as
25 you said, what the expected -- if there is any lumpy

1 revenue requirements. Obviously you're not simply
2 offsetting cap as depreciation in this case.

3 MR. COWDEN: Right.

4 CHAIRMAN WEISENMILLER: So it's not a static
5 situation.

6 MR. COWDEN: Yeah, so we have information we can
7 provide and comments.

8 CHAIRMAN WEISENMILLER: That would be good.

9 MR. KLATT: Could I ask a clarifying question,
10 please? About the price assumptions, I just want to make
11 sure I understood correctly and, actually, I think I may
12 not have understood it correctly. Is it that for the
13 California High and Low case that the price inputs that
14 you used were the same as in the Reference Case? Or was
15 it that the price inputs were the same prices as the High
16 Demand and Low Demand cases?

17 MR. PUGLIA: Peter Puglia at California Energy
18 Commission, Natural Gas Unit. The reference prices, the
19 input prices for all the cases, are identical.

20 MR. KLATT: Okay. So the same exact figures for
21 the starting point on each of the --

22 MR. PUGLIA: That's right. The general
23 Equilibrium Model and econometric modeling will give you
24 different prices in the end, but they all start out the
25 same. As just something that has come up before, if it

1 hasn't been mentioned in the report or the presentations
2 as something that was changed, assumptions that were
3 changed from the Reference Case, then they are identical
4 to the Reference Case. Do you understand that?

5 MR. KLATT: Oh, yeah, that's very helpful. And I
6 think you also answered my second part of my question,
7 which was that, as a result of the modeling for each of
8 the cases that those prices, the actual values would
9 change as you run the model.

10 MR. PUGLIA: That's right.

11 MR. KLATT: So what comes out of that would be
12 different and that affects what the demand scenarios are.

13 MR. PUGLIA: Right, the prices that you begin
14 with are all the same in almost all the cases, they're
15 identical to the Reference Case.

16 MR. KLATT: And then as they go through the model
17 as different - other variables, inputs are changed.

18 MR. PUGLIA: Right. Then, as you know, with a
19 General Equilibrium Model, they solve for the change in
20 demand, price and supply at every node.

21 MR. KLATT: Right, thank you.

22 MR. PUGLIA: You're welcome.

23 MR. KLATT: That's very helpful for me.

24 COMMISSIONER PETERMAN: Just to bang this point
25 into the ground even more, so does that mean in the

1 Reference Case that the output price is the same as the
2 input price? No. Okay. I'll figure it out later.

3 MR. MILLER: It would be turned off for the price
4 elasticity.

5 COMMISSIONER PETERMAN: Oh, okay, right.

6 MS. VU: So let me confirm my understanding. The
7 historical price, that input in the model is the same for
8 all cases, but then the model will solve for the price as
9 an output in each scenario. Is that correct?

10 MR. MILLER: Right.

11 MS. VU: So the models solve for the prices.

12 COMMISSIONER PETERMAN: Yeah, that's a nice
13 little line just to put it in the description if it's not
14 already there because it took me a lot to get my head
15 around that, as well.

16 MR. MILLER: It looks like we have a further --

17 COMMISSIONER PETERMAN: Hold on, Leon is getting
18 up, everyone on the phone.

19 MR. BRATHWAITE: I just want to make a slight
20 clarification here, okay? Yes, we do start with input
21 reference prices, okay? But however, if you change any
22 of the independent variables, like for instance you
23 change your amount of fossil gen, or anything like that,
24 that will give you slightly different reference prices.
25 So the input prices on those cases should be in some

1 cases different -- just to be clear. So, for instance,
2 like in the High Price case, we took out the coal-fired
3 generation, that will generate the front Reference
4 prices. Just to be clear. I mean, I confused the
5 matter?

6 COMMISSIONER PETERMAN: Yeah, can you go back?

7 MR. BRATHWAITE: All right. Do you remember this
8 morning, I'll show Ken his own -- Ken showed you a series
9 of equations, okay? And in those equations he had a
10 bunch of independent variables. Some of those
11 independent variables were fossil generation, is
12 whatever, and that kind of stuff, population, all that
13 kind of stuff and things. If for instance we change
14 population, it will give us the front Reference prices in
15 different quantities. But like, for instance, in our
16 High Price case, we took out 50 GW of coal-fired. So if
17 we take out 50 GW, that changes fossil gen, and it
18 changes some other things, so it should give us different
19 Reference quantities.

20 COMMISSIONER PETERMAN: The quantities will
21 change, but the price input will be -- I mean, piece of
22 NGI, you know, substitute NGIT would be the same across
23 all of those, right?

24 MR. BRATHWAITE: Quantities will change.

25 COMMISSIONER PETERMAN: Quantities will change,

1 but the input prices won't.

2 MR. BRATHWAITE: Oh, the prices we're talking
3 about, okay, fine. Thank you.

4 COMMISSIONER PETERMAN: All right, so, yeah, you
5 were right, Mia. Thanks for that wrap-up. Were there
6 any other comments or questions on that section before we
7 move on?

8 MR. TAVARES: Okay, Commissioners, now that we
9 are clear about the inputs [laughter]... We have our next
10 speaker, Katie Elder. She is going to be presenting the
11 Low Pressure case and this will show you some of the
12 limitations that we were dealing with, especially in
13 regards to natural gas storage because the model does not
14 take into account -- as we have it now -- does not take
15 into account the question of natural gas storage through
16 the year. Nevertheless, we ran the case and Katie is
17 going to describe what we actually did on that case.
18 Katie.

19 MS. ELDER: Okay -- where is the presentation?
20 Okay, I give up. I tried to use my special good doo-dad
21 and it didn't quite work, so there you go. And so that
22 means I think that that button pushes it? Okay, somebody
23 needs to drive for me because I can't reach. Hi, I'm
24 Katie Elder, I'm my usual normal disorganized frazzled
25 self. I've been working with the staff on the Gas

1 Assessment and there are days in which they undoubtedly
2 quake in their boots when I walk in, and other days when
3 they're relieved, so hopefully this part of the analysis
4 is part of them being relieved that I took on this part
5 of it for them. Now I have control, okay. Now Ivin
6 doesn't have to push the buttons for me because I got it
7 to work, lovely.

8 Okay, so what I'm going to talk about with that
9 little interlude there is that part of the analysis that
10 I'm going to show you has a little bit to do with the
11 world gas trade model results, the rest of it doesn't,
12 and I'll explain why.

13 Usually, in the years that I've watched staff's
14 assessments, and that goes back to when none of Leon's
15 beard was gray -- I thought that was good -- a really
16 long time ago, there has always been some sort of point
17 at which staff brings the analysis kind of back to
18 something that is really practical in terms of the
19 state's ability to serve all load. And that's in some
20 respects what this part of the analysis is going to focus
21 on in terms of what happened, particularly as we look at
22 the PG&E system and some of the pressure reduction
23 impacts that we're experiencing in the aftermath of
24 dealing with the aftermath of the San Bruno explosion, so
25 that's what I'm going to walk you through.

1 In this part of the analysis, we tried to look at
2 four general kinds of issues, one is that, in the model,
3 in the World Gas Trade Model itself, we did do a scenario
4 in which we reduced the capacity on the Baja and Redwood
5 Paths, and we brought those capacities down by about 500
6 a day. We did that, we know that the model, as Leon has
7 emphasized, I think Ross emphasized, Ivin emphasized, the
8 model looks at a whole year at a time, its granularity is
9 kind of a total annual demand, which is going to look at
10 it flat, it doesn't give you the ability to look at any
11 peaks or valleys over the course of the year. So we
12 looked at this in annual mode, knowing it probably wasn't
13 likely to show us anything interesting, but as a matter
14 of due diligence, did it anyway to confirm that it
15 wouldn't show anything interesting. If we were able to
16 run the model in its monthly mode, it might show a
17 different result. And so, because of this limitation of
18 the model, that it's only looking at an annual basis over
19 the course of the whole year on kind of an average day
20 look, we did some additional analysis that I'll show you.
21 Those additional analyses include kind of a gas balance
22 approach looking at stacking up total demand against the
23 capacity and the supply you've delivered over that
24 capacity to meet that demand, and then the gas balance,
25 you just basically look at the difference between those

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1 two, one vs. the other, the demand by month vs. the
2 constrained delivery capability.

3 We also give you a look at a peak day using some
4 data that PG&E had in the California Gas Report. We also
5 looked at storage refill capability.

6 In the Pressure Reduction scenario, we changed
7 two key assumptions. One is we reduced that backbone
8 capacity, and there are about three different reasons why
9 that backbone capacity, or the pressure operating on the
10 backbone capacity, is lower and which reduces
11 deliverability on the lines. Some of those reductions
12 were ordered by the Commission, the PUC. Some of those
13 are PG&E's result of its classification study and finding
14 that some lines were misclassified, so if you correctly
15 classify them, their maximum operating pressure should be
16 lower, so they would flow less gas. Some of those
17 reductions are going on as hydrostatic testing and our
18 replacement continues, so those tend to change relatively
19 often as that testing proceeds. As I mentioned earlier,
20 we reduced capacity on the backbone by about 500 a day
21 total, and so we took Redwood System down from its normal
22 of about 2050 MMcf per day down to 1850, and we took Baja
23 down by about 300. Those numbers were based on what was
24 showing up on Pipe Ranger in mid to late July when we did
25 the analysis as being available through year-end. Now,

1 those numbers change, as I said earlier, as PG&E does the
2 testing, is able to bring some lines back up on pressure,
3 it changes based on what segment PG&E had to take out of
4 service on a given day, and so you have to watch those
5 numbers. And I think they changed again last week with
6 Redwood coming back up to 2050, but nonetheless, we've
7 got modeling results that looked at it being lower
8 because that's what we were seeing at the time, and that
9 lets us be conservative.

10 The other big change that we made in the model
11 result was to turn off the capacity expansion because one
12 of the things that the model will do, or that we had the
13 model configured to do was if prices continue to go up
14 and you see basis differentials grow, and our economic
15 actors that we're simulating in the model get the signal
16 that it would be economic to add new pipeline capacity,
17 the model will add it. And so, given that we were
18 constraining capacity and, if it turned out that we
19 needed that capacity, it would be reasonable to expect
20 that the model would see that in the form of a price
21 signal and add capacity, which would not show us any
22 interesting result, it would basically undo the capacity
23 constraint that we had introduced. So we turned that
24 off.

25 The end result of that is that it doesn't show

1 anything exciting or unusual and you can say kind of, "Ho
2 hum, why did you waste your time doing it?" Well, we did
3 it in order to be careful and to make sure that we had
4 the scenario covered. You see a few little annual price
5 changes or perturbations, I'll call them, in price year
6 to year, they're not particularly consistent one year to
7 the next, they're small on a percentage basis, they don't
8 occur just for California, they occur for Henry Hub, as
9 well, and so it's something that's going on in the model
10 that's not specifically germane really to exactly what's
11 going on in California.

12 The other thing that you see is -- and this kind
13 of goes back to some of the questions that I think George
14 from El Paso and Greg maybe from Transwestern mentioned
15 earlier about sort of maybe some question or confusion
16 about the relative selection or flows in the model of
17 Canadian gas vs. Southwest Gas. And what we see is,
18 because the Redwood Path was economically preferred in
19 the model and the Reference Case, that when we constrain
20 Redwood, we then end up shifting those constrained flows
21 from Redwood to Baja. And so you see the impact of the
22 200 a day constraint on Redwood is to shift that to Baja,
23 essentially. But that's the only real change that you
24 see in the model as a result of constraining capacity by
25 about 500 a day.

1 Now, the table here that you've got there, except
2 for this column over here on the right, and if I were
3 clever, I would have made this so that I could just hide
4 that until I was ready to talk about it, but I'm not that
5 clever, so ignore this column for the moment because it's
6 not in the table that's in the study, the rest of this
7 is.

8 What we did in this table is try to illustrate
9 how PG&E would actually meet demand on a cold day. I use
10 this to draw some inferences about what an average day
11 might look like and give some advice, if you will, to
12 core customers and other market participants. The two
13 columns, December 8 Recorded, 2009 Recorded Demand, and
14 on the day after, on the 9th, about 4.1, 4.2 Bcf per day
15 on the PG&E System, and what you see in these rows down
16 here are how PG&E met that demand, and so when these peak
17 days or relative peak days that happened relatively
18 recently occurred just about a couple of years ago, you
19 can see the flows on the PG&E system that allowed it to
20 meet this demand and, in essence, Baja was pretty close
21 to full, Redwood was maybe half full, and then we had
22 some California production added to that. PG&E pulled a
23 lot of gas from storage on that cold December day, and a
24 lot of gas came from independent storage. Same thing
25 really happened the next day, the numbers shifted around

1 a little bit, but it's basically the same story over
2 again.

3 So then what we did is note that we pulled the
4 winter peak day demand from the 2010 California Gas
5 Report and that PG&E's winter peak day demand was about
6 almost 4.3 Bcf, which is pretty close to the September
7 9th, 2009, a little bit higher than the day before by
8 about 100-200 a day, but pretty darn close. And then we
9 said, no, let's see what happens when we have our
10 constrained capacity. And we assume that this capacity
11 would be fully utilized, by the way. So we had 1,800 in
12 for Redwood and 733 for Baja, those numbers are a little
13 bit -- the 733 is just a little bit lower than what we
14 had in the model because there was a change in the number
15 that we saw in Pipe Ranger between the time that we
16 started the model until when we did this analysis, so we
17 went with the more conservative number here. And you can
18 see the kinds of numbers, we assumed a fairly large hefty
19 storage pull from PG&E storage for core customers, and
20 then we had to pull about 500 a day more from independent
21 storage in order to satisfy the 42, the 4.3 Bcf per day
22 demand.

23 Now, interestingly enough, supposing that we were
24 in a scenario in which we had 1,800 available, but
25 customers nominated their gas and they only nominated the

1 number that is more like 800 or 900 like they did back in
2 December 2009, and then you have to pull more gas from
3 storage in order to satisfy all demand. So that's what
4 we wanted to highlight with that particular column.

5 Now, we can turn that into sort of drawing some
6 inferences about what would happen on an average day, or
7 really any day in between, and we just put the same
8 numbers here in this column that I told you earlier not
9 to look at until now, now you can look at it. So we put
10 the same numbers for capacity in here, 1,800 Redwood, 733
11 Baja, 130 or so per day from California production, and
12 we assumed a much smaller, more like an average colder
13 winter month storage pull for PG&E storage, and if
14 nothing came from independent storage, the amount of
15 demand that we could serve under those conditions with
16 those kind of deliveries and capacities available is just
17 about 3 Bcf per day. So that you can see here, between 3
18 Bcf per day and going up to 4.3, basically the entire
19 increment of that has got to be met with gas from
20 storage. So two things that we said in the report, one
21 is that we encouraged non-core customers to make as much
22 use of the existing available backbone capacity for the
23 rest of the injection season as they possibly could, to
24 get as much gas into storage as possible; the second
25 thing, this allows us or leads us to encourage non-core

1 customers, and particularly those who are using
2 independent storage, is to be prepared to use it this
3 December and January if the capacity numbers on the
4 backbone stay where they are. And that's a big "if." As
5 we watch Pipe Ranger, we see it change every day or every
6 couple of weeks, it goes up, it goes down, most recently
7 it's gone up. There have been some days that it went
8 down that were after staff had done its initial analysis,
9 and so what we've learned is that we have to keep an eye
10 on it and continually update our expectations. And as we
11 get closer to winter, of course, PG&E is watching these
12 too, but we're just trying to provide an extra set of
13 eyes and ears on that.

14 COMMISSIONER PETERMAN: Katie, can I interject
15 with a question?

16 MS. ELDER: Yeah. Do you want me to stay on that
17 page?

18 COMMISSIONER PETERMAN: Sure. A little bit of my
19 ignorance about storage. Is there a difference in the
20 PG&E storage and the independent storage besides the
21 capacity?

22 MS. ELDER: There is. In essence, it works this
23 way. Most of the PG&E storage is what we call "old
24 traditional reservoir storage," where basically -- this
25 is not 100 percent true, but think of it as 90 percent

1 true -- they work to fill it all summer long and then
2 withdraw the gas out of that storage over the course of a
3 single winter, and so it's single cycle storage. The
4 independent storage, though, is much higher pressure,
5 high deliverability storage where they can do several
6 injection withdrawal cycles over the course of the year.
7 One of the things that we saw in 2000 with the power
8 crisis and some other events that occurred late that
9 summer with an explosion on the El Paso System at Las
10 Cruces, was that high prices had led non-core customers
11 to delay their storage refill. And then you had this
12 explosion that took out part of the El Paso System, which
13 impeded their ability to fill storage late in the season.
14 We ended up that winter on November 1st going into the
15 winter storage withdrawal season with not having full
16 storage in Southern California, in particular. And so
17 part of what we wanted to be able to tell non-core
18 customers this time was "pay attention, guys, things
19 could get interesting if it gets cold early," and sort of
20 try to get customers that warning early rather than let
21 them sit and potentially not hear that message, and not
22 take advantage of the opportunity that is there now with
23 some spare, but the little spare backbone capacity there
24 is to make sure that that gets used. So that's the
25 general difference between the two. The customers who

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1 tend to use that tend to be not only non-core customers,
2 but marketers, and they tend typically to be playing more
3 of a price optionality game, trying to make money on the
4 margin or on price volatility, rather than using it for
5 reliability. That's not totally true, but it's often the
6 case that that's what they're up to.

7 COMMISSIONER PETERMAN: And those are the ones
8 storing or independent storage?

9 MS. ELDER: Correct. Correct, that's what I was
10 talking about.

11 COMMISSIONER PETERMAN: Thank you. That was very
12 illuminating.

13 MS. ELDER: We also looked at whether or not we
14 thought we could refill storage, which is a great lead-in
15 to this next page, Commissioner. What we did is we
16 looked first at whether or not we thought we could --
17 whether it looked like PG&E would be able to get storage
18 refilled for core customers. We constructed a little
19 analysis, you know, where we start the storage inventory
20 at zero at April 1st, it's not always zero on April 1st,
21 but it's usually kind of close. And then we took the
22 injections and withdrawals that were posted on Pipe
23 Ranger and, by feeding those into a spreadsheet analysis,
24 we could calculate the ending month storage inventories.
25 And so that gave us some confidence with what we were

1 seeing actually go into storage. What we were seeing in
2 terms of backbone availability, that storage indeed for
3 core customers would be filled by November 1st.

4 We then did a second cut at which we looked
5 separately at independent storage. It's harder to look
6 at independent storage because of the multi-cycle
7 capability, you know, PG&E is much easier to look at if
8 you assume one cycle, but when you get into the
9 independents, you've got more than one cycle and their
10 inventory is not posted anywhere, you have to sort of
11 guess a little bit, more -- what's the right word -- a
12 lot more uncertainty about where the inventory is in a
13 given moment. And of course, for competitive reasons,
14 they don't particularly want to share that information.
15 So we went ahead and set it to zero knowing that that
16 could not be reality, but we wanted to see how that would
17 play out, then go ahead and put in the injections and
18 withdrawals that we could see posted from Pipe Ranger.
19 It looked to us like most of the independent storage
20 could be full by November 1st, but probably not all of it.
21 And, again, that just amplified our overall conclusion
22 that we wanted to tell non-core customers to pay
23 attention, use every opportunity they've got to fill
24 storage now, so that the gas will be there in January if
25 we need it in January.

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1 And that's all I've got. Can I answer any other
2 questions? Bob should get to ask first.

3 MR. COWDEN: Can I make a comment or a question?

4 MS. ELDER: I think you're allowed either, or
5 both.

6 MR. COWDEN: I guess first a comment, I think
7 Katie is spot on with the main message that comes out of
8 this in terms of the gentle reminder of customers, fill
9 storage, think seriously about using storage this winter
10 because it's one of the key things in the toolkit to help
11 get customers through the winter, kind of that in
12 addition to a lot of enhancements to our C&G and LNG peak
13 shaving programs that we have. Those will be things that
14 really help get us through the winter.

15 I did have a comment on some of the storage
16 numbers, that I think Katie's expected deliverability for
17 an average day is not an unreasonable number, the 3 Bcf
18 for the total demand. I'm not sure how you derived that,
19 but that's similar to what we have expected in January
20 and February. And like you mentioned, the Redwood
21 capacity is now posted at 2050. The one thing with the
22 storage numbers on the PG&E system is that's an average
23 day deliverability of the 350, but our capability to
24 deliver storage on an average day, or even at the end of
25 the winter, is more like 750 to 800 MMcf a day. So just

1 be a little careful about mixing actual usage and
2 capacities because our actual withdrawal capacities are
3 higher than those numbers. And on a peak day, you know,
4 looking over the last three years in the winter, you
5 know, we've been able to withdraw more than the 1,100.

6 MS. ELDER: Right, but you've also done that
7 because you're relatively conservative on withdrawals
8 earlier in the winter and maintain field pressure after
9 that APD date so that you had the ability to do that. So
10 you can't do that for more than, say --

11 MR. COWDEN: You can't do it for every day
12 through the winter.

13 MS. ELDER: Precisely.

14 MR. COWDEN: Fair enough.

15 MS. ELDER: But you can peak up to it when you
16 need to.

17 MR. COWDEN: You can peak up to it when needed
18 and the likelihood of having a peak day every day in a
19 winter is infinitesimal.

20 MS. ELDER: We hope that that is infinitesimal,
21 yes.

22 MR. COWDEN: So, just kind of to wrap up, good
23 numbers, but keep in mind deliverability actual vs.
24 capability.

25 MS. ELDER: Right and that's why we made sure

1 that we showed December 8th and December 9th from 2009 and
2 showed these much higher numbers, but recognize that you
3 never plan to do that through the whole winter.

4 MR. COWDEN: Right.

5 MS. ELDER: Greg Klatt had his hand up.

6 MR. KLATT: Thank you, Katie. I wasn't sure I
7 understood how you derived the 733 number for Baja.

8 MS. ELDER: The 733 number was posted on Pipe
9 Ranger on a given day. I couldn't tell you off the top
10 of my head now what day it was that it was down that low.

11 MR. KLATT: And then you used that for expected
12 deliverability? I mean, I guess you're saying -- you
13 understand the capacity is much higher than that, but
14 you're saying that is how much you expect they could flow
15 on an average basis?

16 MS. ELDER: Right. PG&E has been posting on its
17 Pipe Ranger website the actual deliverability for
18 individual days and what they expect to be available
19 through December 31st given all the stuff that's going on
20 on the system.

21 MR. KLATT: Okay.

22 MS. ELDER: There have actually been days where
23 it's been lower than 733. But at one point, there was a
24 note that said we think that, from now through the rest
25 of the year, it will be 733.

1 MR. KLATT: All right. So, but it's a product of
2 all the other things that are going on on the system?

3 MS. ELDER: Right, on the hydrostatic testing,
4 the class location study, the individual lines that the
5 CPUC has actually ordered for PG&E to operate at reduced
6 pressure, all of those things together have led to them
7 posting specific numbers on Pipe Ranger, but they update
8 periodically.

9 MR. KLATT: Thank you.

10 COMMISSIONER PETERMAN: Katie, I had just a
11 presentation question. Should the colors mean anything
12 to me?

13 MS. ELDER: No, the colors were there just to
14 highlight for you, just to draw your attention to the
15 difference between what happened in 2009 that was
16 recorded data vs. the assumptions that we made based on
17 the data that we saw on Pipe Ranger in this particular
18 column, and over in the green column, I guess we were
19 saying an average day is green.

20 COMMISSIONER PETERMAN: Thank you for explaining
21 that.

22 MS. ELDER: Can I answer anything else? Cool.
23 So we're back to Ruben and Ivin, then.

24 MR. TAVARES: Okay, thank you Katie. Okay, now
25 we have Ivin Rhyne, he is our Office Manager and he's

1 going to address the summary and also some potential work
2 that we may do over the next couple months.

3 MR. RHYNE: All right, so I have the enviable
4 position of talking to a room full of people who have
5 been staring at graphs, charts, numbers, and have been
6 talked to about potential future maybe uncertainties
7 about natural gas, and wrapping this up for the day. I
8 do want to emphasize a couple things. First of all, a
9 very important date, October 11th, 2011, that is the day
10 that we're asking for submission of comments. I would
11 really encourage those of you who intend to submit
12 comments to please do so early and voluminously,
13 hopefully, and thoughtfully.

14 Really this whole process is not about what we
15 just think in a cocoon or a shell, it's about what we
16 think and how that interacts with what our stakeholders
17 think, and how we can improve things going forward. Over
18 the next couple of months, we're going to take that
19 feedback, a lot of the feedback, really excellent
20 feedback and I want to thank all of our panelists who are
21 here, and some who had to take off early, for
22 participating, also for the audience members who
23 participated. I want to also really just extend a thank
24 you from the staff to the Commissioners, who have been
25 very supportive of this whole process as we go through

1 this, they've been very engaged with this, as well.

2 Now, over the next few weeks, as you contemplated
3 your comments, I'd like to leave you with just three main
4 questions, the first one being, and this one is pretty
5 straightforward, what issues or problems do you see with
6 the scenarios as they're currently constructed in the
7 Reference Case? There have been a few questions raised,
8 and as you take this, as you digest it, that kind of
9 feedback is going to be very important for making sure
10 that we improve the quality of the analysis that we've
11 done to date.

12 The second question, what other or different
13 scenarios do you think would be of value for us to run
14 and why? So, we're not going to promise that we have
15 unlimited resources, or unlimited time, but certainly
16 that information and feedback with regard to what
17 additional analyses could be done would also be very
18 valuable.

19 And finally, the third question, and in this I
20 want to be very careful not to limit your thinking with
21 regard to the forecasts or the values that we put forward
22 here, but what gas-related policy recommendations would
23 you propose and why? Certainly, there is a lot of
24 decisions that could be made with regard to natural gas
25 going out in the future, this is a natural time, a

1 natural point for us to be looking out into the future,
2 so those policy questions, what are some policy relevant
3 recommendations that you would make, and why?

4 I would also like to emphasize once again that
5 staff does not have a crystal ball, we don't look out
6 into the future and tell the future, if we did, we would
7 be in the lottery business, not the natural gas business,
8 or, I don't know, it depends. The point being that we
9 have some tools that are extremely powerful and extremely
10 useful, and we attempt to make good use of those tools
11 with regard to the questions at hand, but we're always
12 looking to do better, we're always looking to do more,
13 we're always looking for ways that we can improve what we
14 do with regard to the feedback, what is valuable to you
15 as a stakeholder is certainly of interest to us as the
16 State staff with regard to natural gas. And so, with
17 that, I'm going to stop pestering you with my comments.
18 I'll turn it over to the Chairman and Commissioner
19 Peterman, if you have any closing thoughts before we wrap
20 up for the day.

21 COMMISSIONER PETERMAN: Thanks, Ivin. First, I'd
22 just like to make sure we open it up to any public
23 comments. Is there anyone in the room who has been
24 wanting to say something, but hasn't found the right
25 time, or on the phone lines? Great, glad that you're all

1 satisfied with the forecasts as they are, just kidding.

2 Chair.

3 CHAIRMAN WEISENMILLER: I would certainly like to
4 thank the staff for their hard work on this and certainly
5 thank the participants in the workshop today for giving
6 us good feedback on this report. We're certainly looking
7 forward to moving forward; obviously, these are
8 complicated issues, but I think in terms of trying to get
9 an understanding of what some of the policy connections
10 are, what the uncertainty is and how that plays back and
11 forth with our policy decisions, is always helpful.

12 COMMISSIONER PETERMAN: I agree and I want to
13 thank staff for their hard work on this report. In
14 particular, what I was looking for with this report was
15 to see some of the policies that we've just implemented,
16 or that we're talking about now, such as the 33 percent
17 RPS, the 40 percent RPS, a DG goal, reflected in one of
18 the scenarios. And indeed, you can look at the High
19 Price, the Low Price cases, High Demand, Low Demand cases
20 in California, and see how that could include some of the
21 scenarios we've talked about. And I look forward to the
22 next iteration and continued involvement by all the
23 stakeholders. Thank you so much for being here,
24 particularly to our panelists, Ms. Vu, and Mr. Wilder.
25 Thank you. We are adjourned.

1 ((Adjourned at 3:35 p.m.)

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