COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
INFORMATIONAL PROCEEDINGS AND	)	Docket No.
PREPARATION OF THE 2003	)	02-IEP-01
INTEGRATED ENERGY POLICY REPORT	)	
	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 10, 2003

Reported by:
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Contract No. 150-01-005

COMMISSIONERS PRESENT

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William J. Keese, Associate Member

STAFF PRESENT

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Judy Grau

Melissa Jones

David Vidaver

Karen Griffin

OTHERS PRESENT

Morteza Sabet

Chris Bing

Robert Sparks

Steven Kelly

David Arthur

Devra Bachrach

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

2 9:35 a.m.

3 PRESIDING MEMBER BOYD: Good morning,

4 everybody.

5 AUDIENCE: Good morning.

6 PRESIDING MEMBER BOYD: That's what I

7 like, an audience that talks back. That's the

8 idea. Well, welcome to what some of us are forced

9 to say is yet another in the continuing series of

10 workshops that we have been having, and will be

11 holding more of this month in support of the

12 California Energy Commission's Integrated Energy

13 Policy Report.

14 I'm Commissioner Jim Boyd. I'm the

15 Presiding Member of the Committee that was created

16 to be responsible for this report. And I'm joined

17 by the second member of the Committee, Commission

18 Chairman Keese.

19 The Committee was established by the

20 Commission to, as I said, oversee the development

21 of this report to preside at various proceedings

22 like this, which report was required by Senate

23 Bill 1389, past by the legislature, signed by the

24 Governor.

25 The legislature has often repeated

1 that's their responsibility of state government to
2 ensure reliable supply of energy to see that it is
3 maintained at levels consistent with the needs to
4 protect the public health, safety, welfare, and
5 environmental quality in this state, as well as to
6 support the California economy.
7 The so called Integrated Energy Policy
8 Report is designed to identify merging trends
9 related to energy supply, demand, price,
10 conservation and efficiency majors, and public
11 health and safety issues. And ultimately to
12 provide a basis for state policy and state
13 actions.
14 The Energy Commissioner is required to
15 submit this report to the Governor and legislature
16 by November of this year, and to update it and
17 submit a report every two years thereafter. As I
18 indicated, we are conducting, have, and will
19 continue to conduct a number of public policy
20 workshops on different energy related subjects
21 that we are considering in preparation of the, as
22 call it, IEPR.
23 The purpose of the workshops is of
24 course to receive public comments and technical
25 feedback to establish a factual record, and to

1 inform the committee and ultimately the Commission
2 on the relative and the necessary energy policy
3 choices.
4 We've already discussed in previous
5 workshops were loyal issues, electricity
6 efficiency opportunities, hydropower system, and
7 environmental concerns, air missions, public
8 health considerations, all of which are associated
9 with energy use here in the State of California.
10 Today's workshop, and tomorrow's
11 workshop, are focused on potential electricity and
12 natural gas infrastructure concerns that
13 California may need to address throughout the rest
14 of -- at least throughout the rest of this decade.
15 Senate Bill 1389 specifically calls for
16 an assessment of the electricity and natural gas
17 system, which includes the consideration of many
18 different system elements ranging from demand
19 trends, transmission developments, and regional
20 market implications, certainly events of the last
21 three or more years have exposed extreme
22 vulnerabilities of the state's electricities and
23 natural gas system.
24 And are a deep concern to many agencies,
25 in particular this agency. This committee

1 believes the most pressing issue is whether these
2 vulnerabilities are still a concern or whether
3 administrative, legislative, regulatory and
4 private sector actions, in response to recent
5 events, have addressed the vulnerabilities, at
6 least for now.
7 To address this issue, the Committee
8 believes we need a better understanding of the
9 state's energy infrastructure, because strong
10 energy infrastructure is paramount to California's
11 economic and environmental future.
12 Having said all this, I would like to
13 first turn to Chairman Keese for any comments he'd
14 like to make, and then turn to the staff to hear
15 about the findings of their recent studies and
16 efforts. And Al Alvarado, staff, will provide an
17 overview of the workshop immediately following
18 Commissioner Keese's comments.
19 CHAIRMAN KEESE: I'll reiterate a
20 comment that I've made at a number of the previous
21 events that we've had, which is we start with the
22 assessment, and that will be by staff and the
23 participants here in the room. But we end up with
24 the recommendations we will be making to the
25 Governor for state energy policy.

1 And that's what we seek your input on,
2 what recommendations should we wind up with at the
3 end? We have to agree on the assessment,
4 uniformed assessment. All of us seeing
5 electricity and natural gas the same way would be
6 really helpful. But then the important thing is
7 what are those recommendations?
8 And to the extent that you can help us
9 out by crafting the recommendations that you
10 should think we should be considering, we would
11 appreciate it.
12 PRESIDING MEMBER BOYD: Mr. Alvarado.
13 MR. ALVARADO: Good morning. My name is
14 Al Alvarado. I'm the project manager for the
15 electricity and natural gas report. This is one
16 of three subsidiary reports that are being
17 prepared to support the Integrated Energy Policy
18 Report.
19 So the purpose of today's workshop is to
20 discuss and receive comments on the findings of
21 the staff, electricity infrastructure assessment
22 report that was posted on the Commission's website
23 on May 27th. The analysis that is presented in
24 this staff report will build on the five staff
25 draft reports that were released back in February.

1 And was the subject of a previous IPR
2 workshop. Staff has updated the assumptions used
3 in the infrastructure analysis based on the public
4 comments we had received from this workshop. The
5 staff energy system studies evaluate the
6 implications of a number of important
7 uncertainties on the integrated electricity and
8 infrastructure.
9 The primary goal is identify factors
10 that may stress the energy infrastructure, and
11 determine if there's need for any additional
12 development to mitigate potential supply
13 shortfalls over the next decade. Considering that
14 electricity generation is a primary energy sector
15 that may have the largest on future natural gas
16 demand, the energy infrastructure study is focused
17 on potential stresses to the natural gas fuel
18 system.
19 Tomorrow's workshop will cover the
20 findings on the natural gas system studies. The
21 discussion and technical feedback that we receive
22 at today's workshop, and during the next several
23 events, as Commissioner Boyd had pointed out, we
24 have a whole series of different workshops this
25 month.

1 And there is a list of the other events
2 up at the front desk. The discussions and the
3 comments we receive will serve to refine the staff
4 energy system studies, and also in the preparation
5 of the draft electricity natural gas report. This
6 electricity natural gas report is targeted to be
7 released for public review on July 25th.
8 And as Commissioner Boyd pointed out,
9 the tentacle analysis as included in this report
10 will provide the findings to support any
11 development of policy recommendations that the
12 Committee may consider for the final Integrated
13 Energy Policy Report.
14 So we are interested in hearing from
15 you, your views and your perspectives on today's
16 subject matter. We will be transcribing this
17 workshop to help us track all of your comments.
18 So this will require you, if you have any
19 comments, at least come to the front desk, a
20 microphone over here, and identify yourself.
21 And please provide a business card to
22 our court recorder. This will help us keep track
23 of who you are in our transcripts. Again, the
24 purpose here is hear from you. So hopefully we
25 can have a rather lively discussion.

1 Today we're going to have two staff
2 members that's going to provide an overview of the
3 basic assumptions and the findings that are
4 contained in this report. We have David Vidaver
5 who's in our electricity analysis office and has
6 been responsible for conducting most of our
7 electricity system studies.
8 And we also have Judy Grau from our
9 engineering office who will cover related
10 transmission issues. So with that being said, I
11 think I'll turn to David.
12 MR. VIDAVER: Good morning. How close
13 do I have to get to this damn thing? Okay. Good
14 luck. I'm going to fade in and out.
15 PRESIDING MEMBER BOYD: David has been
16 described an eight-inch cone of acceptability in
17 front of this microphone.
18 MR. VIDAVER: Okay. Sorry, wrong copy I
19 think. Sorry. The only people who weren't
20 laughing were the lawyers who going what's funny
21 about that? I was asked to make this pretty
22 simple. So as Al said, I'm going to discuss
23 generation adequacy.
24 Judy Grau will follow me and discuss
25 transmission issues. So this is as simple as it

1 gets. Current market conditions, which we're all
2 pretty much in agreement about. Projections for
3 2004/2006, which Commission staff is somewhat
4 confident about. But you're welcome to take
5 potshots. I'm sure you will.
6 And then concerns for 2007, which is
7 choose apocolyptics and aria. Let's see here, so
8 this give the illusion of simplicity. It will
9 probably be a little more challenging than that.
10 Current market conditions, this is a graph of spot
11 market prices, both electricity spot market prices
12 and natural gas spot market prices over the last
13 two years.
14 For those of you who can't see the
15 screen, natural gas is at the top. Peak and off
16 peak prices at the bottom. These are monthly
17 averages taken from economic inside and NGI.
18 They're unrated. So if they're off, please accept
19 my apologies.
20 The left hand access is dollars per
21 megawatt hour. The right hand access is dollars
22 per MMBTU, a little diversion. The question is
23 often asked who cares about spot market prices?
24 We at the point we're procuring 95, 98 percentage
25 of energy forward. And the spot market prices may

1 or may not have any real relevance.
2 While some may disagree, it's the
3 contention of staff that spot market prices do
4 serve as bench marks for not only short-term
5 contracts, but long-term contracts as well,
6 hedging decisions. And most importantly, the
7 decision to build new capacity.
8 There are those who would claim that new
9 capacity decisions are simply a function of
10 whether or not you'll have a long-term contract
11 for your output. And well it may be true at the
12 moment, very few new plants are going forward
13 without long-term contracts.
14 This would arguably be subject to
15 change. It's spot market prices all of a sudden
16 peaked for one reason or another. As you can see
17 from the graphs, spot market prices are tracking
18 the natural gas price at an implied heat rate that
19 reflects competition.
20 Spot markets have been competitive since
21 July of 2001 for a couple of reasons. One is that
22 we've added net 7,000 megawatts of capacity in
23 state. Similar figures exist for the northwest
24 and the southwest. And consequently, we have a
25 capacity surplus. In addition, we've stopped

1 procuring energy in the spot market for the most
2 part.
3 This is having an effect on spot market
4 prices and more and more megawatts of capacity or
5 chasing fewer and fewer megawatt hours of demand.
6 We have had a large number of cancellations.
7 There are a lot of new plants that haven't gone
8 forward.
9 I'm not sure that the significance of
10 this has not been overstated. I read the other
11 day that of 110,000 megawatts of proposed
12 additions in the WECC. 80,000 megawatts of those
13 have been canceled. And this is a sign we're in
14 trouble.
15 And all could think was, well, we're
16 really lucky that 210,000 megawatts weren't
17 announced and 180,000 weren't canceled, because
18 we'd all probably be sitting in the dark.
19 Regarding reliability, we've had two events in the
20 last two years of significance, which people
21 indicate that we face present reliability problems
22 at a regional sense.
23 July 10th, of 2002 a stage I emergency
24 was declared. At that time, temperatures in
25 Northern California were, I believe, at one and 15

1 years highs. Similar temperatures were observed
2 in the northwest. The transfer capability on
3 major transmission path from the northwest was
4 reduced for a number of reasons.
5 A large number of units were out on
6 force maintenance, coincidentally the price cap
7 had been lowered down to $55 the previous day.
8 And as result, there was not a lot of capacity in
9 the market. We ended up, the ISO ended up,
10 declaring a stage I at which point, I think, 14 or
11 1,500 megawatts of inter-roundables were called,
12 and the situation resolved itself.
13 The only reason it was necessary to call
14 a stage one is the interruptables couldn't be
15 called until an emergency had been declared. So
16 in fact, despite all the adverse conditions, we
17 were really never in danger of having lights go
18 out.
19 So that should take care of concerns
20 regarding 2002. We also have on the 28th, of May
21 of this year, a couple weeks ago, the stage I was
22 declared again. But this occurred largely as a
23 result of the ISO and everyone else failing to
24 forecast the temperature spike.
25 And had the ISO forecast temperatures

1 accurately, there would not have been 11,000
2 megawatts of capacity out on economic outages.
3 And arguably there wouldn't have been 3,200
4 megawatts of planned maintenance at the time.
5 So contrary to what was reported in the
6 press, the events of the 28th, are not really a
7 sign of things to come. But we do appreciate
8 they're encouraging everyone to continue to
9 conserve. So, let's see, projective 2004 to 2006
10 conditions, these numbers are all in megawatts.
11 They're all dependable. I was asked to
12 reduce the numbers on this chart. So of course I
13 removed the headers, the first column refers to
14 2004. The second to 2005, and the third to 2006.
15 These are statewide numbers. They're dependable
16 capacity.
17 The Commission has been accused
18 occasionally of using name plate capacity or some
19 other inappropriate indicator of how much capacity
20 is available in this state. The expected
21 available generation includes such things as a
22 hydro D-rate to account for the possibility of a
23 (indiscernible) water year.
24 It includes forced outages assumptions
25 that are quite conservative. We assume, I believe

1 it's 3,750 megawatts will be forced out on peak on
2 average. We attribute 2,750 megawatts to the ISO
3 control area. When in fact, in 2002 the average
4 number of megawatts down in the ISO during the
5 summer was about 2,100.
6 So we're deliberately conservative. The
7 net additions reflect our assumptions regarding
8 the addition and retirement of capacity. We
9 assume at 4,400 megawatts of capacity will be
10 added, 2,800 megawatts of capacity will be retired
11 over the next three years.
12 We're going to go into those numbers in
13 more detail. The resulting operating reserves
14 between 14 and 17 percent over the next three
15 years indicate that even under adverse weather
16 conditions we should not have to turn the lights
17 out. These numbers all assume that capacity will
18 be available to California load-serving entities.
19 It's been stated that this is apt to be
20 wrong, that some capacity, perhaps a large
21 quantity, maybe contracted to load-serving
22 energies out of state. We admit that we don't
23 have an adequate amount of information in this
24 regard. Generators are not required to inform us,
25 or anyone else, of any contractual obligations

1 that they have, not only out state, even in state.
2 However, the rather large surpluses that
3 exist in the northwest and southwest today would
4 seem to indicate that it's unlikely, even on peak,
5 a large amount of capacity in California will be
6 committed elsewhere. I should return the expected
7 available generation number and say we're also
8 assuming the availability of 2,700 megawatts of
9 spot market imports.
10 This number is based historical
11 analysis. This roughly the same amount of energy
12 that California was able to obtain from the
13 northwest and southwest on peak in 1998 and 1999.
14 Certainly the transfer capabilities of the grid
15 are the same. And there is more surplus available
16 from the northwest and southwest than was the case
17 in 1998 and 1999.
18 These regions have added a large amount
19 of capacity. We've published those numbers
20 elsewhere. Loads in the northwest continue to
21 remain at early and mid 1990s levels largely due
22 to the demise of the aluminum industry. Six
23 percent of the northwest loads have all but
24 disappeared.
25 The additions and retirements that we

1 assume in 2004 through 2006, these are
2 conjectures. We assume that 4,300 megawatts of
3 dependable capacity will be added over the next
4 three years. 3,100 of this consists of projects
5 that have been proposed or are under construction
6 by load-serving energies in the State of
7 California.
8 They are going to be used to mitigate
9 exposure to the spot market, to replace existing
10 facilities that will be retired, and to replace
11 contracts that are due to expire. Because these
12 projects are being put forth by load-serving
13 entities, we assume that they will be built.
14 We assume only two merchant projects
15 will go forward in the next three years. In our
16 studies we assume that those projects are Metcalf
17 and Otay Mesa. However, the results of our
18 analysis don't fundamentally change if you assume
19 it's two other projects of equal size.
20 And there are several projects, which
21 could be on line by 2005, notably Mountain View,
22 Palomar. Staff acknowledges that there are
23 liquidity problems. It says we were getting
24 merchant plants on line, and the low forward
25 prices would seem to a addition to bringing plans

1 forward.

2 But if those who are predicting an

3 apocalypse are correct, and that 8,000 megawatts

4 of capacity will be retired over the next two

5 years, or some other large numbers, loads will

6 increase and we will have a crisis by 2005 or

7 2006. It would seem logical one or two of these

8 merchant plans might wake up and smell the coffee

9 and finish construction.

10 The retirements that we assume 2004 to

11 2006 are primarily plants which will -- I'm losing

12 my train of thought. I'm sorry. The retirements

13 that we assume in 2004, '05 and '06 are primarily

14 plans which have attentions to retire. Many of

15 them would be replaced by Repowers, Valley and

16 Haynes for LADWP.

17 We assume Hunters Point will be retired

18 at the end of 2005. We have already retired a

19 large number of facilities that are shut down due

20 to the need to add emissions controls, which

21 owners have felt were not cost effective given

22 anticipated forward prices.

23 So much of the retirements that are apt

24 to occur, due to tightened emissions constraints,

25 have already taken place as far as we're

1 concerned. They are not reflected in these
2 numbers because we assume they retired at the end
3 of 2002 or in early 2003. This is about 1,700
4 megawatts of capacity.
5 1,200 megawatts largely due to rule 2009
6 and the south coast air base, some capacity in San
7 Diego, which is leased with the US Navy. We
8 assume for example that Pittsburgh Three and Four
9 are already retired. They're not reflected in
10 these numbers. I'll return to retirements in more
11 detail because they do reflect a risk that the
12 state faces during the coming two or three years.
13 The high reserve margins that we
14 anticipate will prevail during the next three
15 years, minimize the likelihood of shortages, of
16 reliability concerns. And it says here the price
17 spikes. By the time the day market opens
18 load-serving energies will have secured energy and
19 capacity to meet a lion's share of their load.
20 The exact percentage is going to depend
21 on activity, future activity and the PUC's
22 procurement proceeding. Reduced reliance on the
23 spot market means that large quantities of
24 capacity are chasing a relatively small amount of
25 demand. This has been cited as primary reason for

1 competitive spot market as of July 2001 in
2 California.
3 And staff feels that these conditions
4 will continue to prevail. Generators no longer
5 have incentive to withhold capacity from the
6 market, nor do they have the ability to offer
7 energy at values substantially in excess of their
8 cost of generation. As I mentioned, substantial
9 surplus is in neighboring states.
10 It reduce the demand for California
11 exports. Meaning that more capacity in California
12 will be bidding for California loads. Our
13 simulation analysis indicate that under the
14 assumptions that we made regarding additions and
15 retirements, no unserved energy is expected in
16 California, or on peak, except perhaps in San
17 Francisco in 2004 prior to the expansion of the
18 Jefferson-Martin line and a greater import
19 capability, and the addition of 180 megawatts at
20 peaking facilities that are expected to be added
21 in San Francisco in 2005.
22 One caveat, a competitively priced spot
23 market doesn't necessary mean that prices are
24 going to be low by historical standards. Prices
25 will continue to be driven by spot prices for

1 natural gas. As gas prices apt to be high
2 throughout the remainder of the year, storage is
3 increasing -- excuse me, competing with
4 consumption.
5 You're all familiar with current issues
6 on the natural gas market. Failure to inject an
7 adequate amount of gas into storage could lead to
8 higher winter prices. As recounts, you're
9 increasing. It's expected that prices are going
10 to fall next year, but nothing is certain. In my
11 mind, even less as certain because I don't know a
12 whole lot about this. The gas unit is going to
13 talk tomorrow.
14 Staff's conclusions regarding conditions
15 in 2004 and '06 are predicated on load serving
16 energies continuing to hedge exposure in the spot
17 market during the next couple of years. For the
18 IOU's this simply means approval by the PUC of
19 necessary four contracts, including those that
20 would replace expiring contracts, either DWR
21 contracts or QF contracts.
22 Municipal utilities are soon to continue
23 to minimize exposure to the spot market using both
24 existing and new capacity, and forward contracts
25 to do so. In addition, staff assumes that

1 existing access providers will not rely
2 excessively on a spot market to meet obligations.
3 These providers are assumed to prudently
4 manage their risks, required to do so is necessary
5 by legislation or statute. That the direct access
6 providers presently are in a position where they
7 don't necessarily have to prudently manage risks.
8 This is an issue of concern for the
9 investor of utilities who may, under some
10 scenarios, be faced with the task of suddenly
11 serving loads for direct access. So we assume
12 that this is not going to be the case, that you
13 won't suddenly have two or three megawatts of
14 demand appear in the spot market.
15 The primary risk, we feel is being faced
16 ratepayers is the risk of high natural gas prices.
17 Ratepayers are exposed to this risk through spot
18 market purchases, QF contracts, index to gas,
19 dispatchable DWR contracts. There is one must
20 take DWR contract that's index to gas, and all
21 short-term contracts.
22 Those are six months or less. High
23 natural gas prices can result from transient
24 weather conditions, for example an arctic cold
25 snap, dry hydro conditions, or other seasonal

1 weather patterns, which went in storage. These
2 risks could be hedged to some extent.
3 It's our understanding that investor
4 owed utilities are seeking to do this through the
5 procurement proceeding at the PUC. We assume that
6 the PUC will allow them to continue to do this as
7 long as it's in the interest of ratepayers. We
8 also assume that municipal utilities hedge their
9 gas price risk.
10 So returning to retirements, staff feels
11 that several factors should limit retirements
12 during the next three years. Well, the subsequent
13 -- a substantial share of the state's generation
14 fleet is old and due to retirement. We also note
15 that information needed to access the likelihood
16 of retirements is confidential, and often
17 subjective.
18 Staff is not well positioned to analyze
19 the likelihood of retirement on a case by case
20 basis. That being said, we believe there's
21 several reasons we'll see capacity stick around
22 for two or three years. One is the RMR contracts,
23 a small share of the state's agent capacity is
24 actually obligated to provide energy capacity
25 under a long-term RMR contract -- excuse me, the

1 DWR contract.

2 RMR contracts are keeping generation in

3 San Diego afloat. A substantial amount of

4 generation in San Francisco as well, and a small

5 amount of generation in the south coast. The need

6 for capacity on the part of load-serving entities

7 we feel is going to encourage some generators to

8 stick around, as long as the PUC continues to

9 allow the IOUs to hedge price risk by contracting

10 forward.

11 We feel that a substantial amount of

12 capacity is going to stick around. And finally,

13 the substantial uncertainty regarding the

14 development of new capacity over the next two

15 three years, as well as uncertainty regarding

16 transmission upgrades, is going to result in

17 plants sticking around.

18 The decision to retire is irreversible.

19 Once you dismantle your plant you can't change

20 your mind. It was forecast in 2001 that by 2003 a

21 large portion of the state's fleet would be gone.

22 We argued at that time that it would continue to

23 stick around due to various uncertainties,

24 including regulatory uncertainty.

25 We don't feel that that situation has

1 substantially changed. That being said, there are
2 several large plants in California which are faced
3 with the obligation to install emission controls.
4 Their risk is on the slide. It's actually quite a
5 short risk. A large share of the plants that have
6 been faced with this decision have already made
7 it.
8 They're either still in operation or
9 they've been retired. The plants, two of the
10 plants listed, Pittsburg 7 and Contra Costa 6 are
11 in a rather unique position. The ISO reported
12 last week that its RMR requirements for the San
13 Francisco Bay Area are apt to drop substantially
14 from 7,800 to 3,600 megawatts.
15 This is going to make it very difficult
16 for Pittsburg 7 and Contra Costa 6 to provide
17 competitive bids for RMR services if they expect
18 to recover the cost of installing emissions
19 controls. As this is something that we've just
20 been faced with within the last week, we're not
21 really in a position to evaluate the likelihood
22 that Pittsburg 7 and Contra Costa 6 will have the
23 incentives to retirement.
24 It should be noted that they both
25 operated a substantial number of hours in 2002,

1 the extent of which that will be the case in 2004,
2 2005, and 2006 is questionable. Our simulation
3 show that from the perspective of the market there
4 needed less and less. If they're not needed from
5 a reliability prospective, and do not procure more
6 contracts, it's a possibility that they would have
7 incentives to retire.
8 Okay. Now, that we've painted such a
9 rosy picture, albeit with a great deal of
10 uncertainty, it appears as though spot market
11 prices in 2004 through '06, while competitive, are
12 not apt to provide incentives for new capacity.
13 The resulting sparks spread are quite low.
14 This should not be taken to mean that
15 individual developers may not have more optimistic
16 outlooks. The decision to bring a plan on line in
17 2005 is less dependent on one's forecast for
18 prices in 2005 than it is for prices in 2006, '07,
19 '08, '09, '10.
20 If individual developers perceive that
21 the rather apocalyptic predictions of some
22 analysts are apt to be borne out, staff believes
23 that these plants would simply come on line. Give
24 the current surplus, load-serving entities may not
25 have incentives to forward contract for all the

1 peak load.

2 Prudent portfolio management arguably

3 will dictate for a load-serving energy to rely on

4 the spot market for its last few percentage of

5 load when it feels that spot market prices are

6 going to be reasonably low and stable. Given that

7 that's the forecast for the next couple of years,

8 we would expect that load-serving entities will,

9 if not lean on the spot market a little bit, they

10 will certainly rely on very, very short-term

11 contracts for a share of their load.

12 As such, there's little incentive for

13 new capacity based on the short-term contracts.

14 The addition of capacity is encourage by allowing

15 load-serving entities to enter into long-term

16 contracts. We assume that the PUC will do that as

17 part of the long-term procurement proceedings and

18 the long-term plans being submitted by the

19 utilities.

20 However, in the current market there is

21 an excess amount of base load capacity. This was

22 acknowledged by PG&E in their long-term filing.

23 They believe they have an adequate amount of --

24 there is an adequate amount of base load

25 generation in the state through the end of the

1 decade.

2 The problem is peaking capacity. As

3 long as you anticipate stable and reasonably low

4 spot prices there's really no incentive to go out

5 and sign capacity contracts, contracts for peaking

6 capacity that might incent new peaking generation.

7 So what this is all intended to say is

8 that, even if load-serving entities go forward and

9 sign long-term contracts to the extent that it's

10 prudent to do so, there is no guarantee that

11 allowing utilities to engage in prudent portfolio

12 management is necessarily going to lead to a

13 reliable electricity system.

14 There's no guarantee that even in this

15 environment the market is going to cough up and

16 adequate amount of peaking capacity in a timely

17 fashion. So one thing that could ensure that are

18 rather stringent resource adequacy requirements.

19 Those are being discussed in Washington.

20 They're being considered here in California.

21 There is of course that tradeoff between a

22 resource adequacy requirement that requires

23 ensuring sufficient capacity to keep the lights

24 on, and reducing the amount of flexibility that

25 both serving entities have to meet load in a cost

1 efficient fashion.

2 In other words, to take advantage of,

3 for example, demand site programs that might serve

4 us. So the upshot of these less than novel

5 observations is that the state will have to

6 continue to monitor the market to ensure that an

7 adequate amount of capacity is available, and to

8 allow utilities to offer incentives for new

9 capacity when it's deemed necessary.

10 We simply can't get away from the fact

11 that information is a paramount concern and that

12 there is a fine line between requiring the

13 addition of new capacity when it may not be

14 necessary. And assuming that the market will

15 provide when it in fact may not.

16 Our final concern relates to local area

17 reliability. San Francisco and San Diego

18 illustrate that under certain circumstances

19 regulators may have to, and I use the word here

20 "compel", solutions to local reliability problems.

21 I'm going to use the less sensitive example of San

22 Francisco.

23 It appears as though between the

24 expansion of the Jefferson-Martin line and San

25 Francisco's intention to add peaking capacity that

1 local reliability problems in San Francisco have
2 been forestalled for let's say five years. But in
3 the even that Jefferson-Martin were not built, in
4 the event that Hunters Point were to be shut down
5 due to local concerns, we'd be facing a very
6 serious problem, and that is you would not be able
7 to meet local reliability criteria in San
8 Francisco.
9 That being the case, it would be
10 incumbent upon the regulator community to
11 prescribe a solution. To date the regulators have
12 avoided doing that, allowing San Francisco to come
13 up with a solution which met local concerns. This
14 appears to have been successful.
15 San Francisco will no doubt go forth
16 with energy efficiency programs, demands on
17 management program, and generation options, which
18 will meet its concern for the environment, and
19 environmental justice. However, this is not a
20 necessary outcome.
21 It's possible that at certain times and
22 certain places that the state would be in a
23 position where it would have to literally compel a
24 certain solution in order to keep the lights on.
25 And that is something that has to be kept in mind.

1 Staff simulated the market under a set
2 of assumptions for 2007, 2013. It did so in large
3 part to provide input and other analysis being
4 done by the Commission, analysis related to
5 emissions, gas use, etcetera. As was stated in
6 the report, this is not a forecast. This does not
7 assume that the state and the market together will
8 ensure an adequate amount of capacity.
9 It was just simply a logical baseline
10 from which to analyze the effects of other
11 policies. To assume that the market would fail
12 and the state would be unable to do anything about
13 it did not seem to be a prudent basis for planning
14 an analysis.
15 The assumptions regarding the additions
16 in retirements we used in these scenarios are
17 stated elsewhere in the report. We added
18 renewable resources needed to meet RPS targets.
19 We assumed continued funding in efficiency
20 programs at comp levels.
21 And we came up with spot prices in the
22 36 to $49 range treading upward due to the
23 eradication of the regional capacity surplus that
24 we anticipate will exist in 2006 will be gone in
25 about 2008, 2009. And we also assume that natural

1 gas prices continue to rise, I believe two percent
2 real.
3 But that could be slightly off. One
4 thing that comes out of this is even with
5 renewable portfolio standard targets being met,
6 California is increasingly going to rely on
7 natural gas for generation. The left axis is
8 gigawatt hours. The right axis is percentage of,
9 let's see, how do I put this, it is the percentage
10 of total California demand that is met by gas
11 generation in state.
12 This is not a contractual arrangement.
13 It's simply the amount of gas generation taking
14 place in California divided by state demand. You
15 can see that the numbers increase from about 32,
16 33 percent up to 48 percent or so over the next
17 ten years. This poses additional risk to the
18 ratepayers of the state.
19 In the short run, natural gas price
20 volatility can be mitigated using largely
21 financial instruments and storage. In the longer
22 run rate bearers will be exposed to our natural
23 gas prices for either of two possible reasons.
24 One is cyclical development and exploration for
25 natural gas, which creates a gas price cycle of

about two or three years in duration.

We are apparently on the upswing right now, crest and rises as to how much longer that's going to continue. A second source of risk is the notion of dwindling supplies. It is prospected by many that due to increasing extraction costs, limitations on where drilling can take place, depletion of swallowing well drilling in the Gulf of Mexico, that we are doomed to face higher gas prices as we move forward.

These risks can't be mitigated using financial instruments except at very, very high costs. There are some ways one might mitigate these risk. If you can get someone to build an LNG terminal and then sell you gas at ten percent about his cost for the next 20 years, that's one way to do it.

And easier way to do it is simply reduce the demand for electricity, or replace gas generation with generation that uses other fuel sources. Regarding the latter, one of the caveats is you can't then turn around and index the cost of that generation to gas when you've defeated the purpose of turning toward it as a fuel.

So staff ran a scenario in which the

1 public discharge was increased. This resulted in
2 DSM savings and additional renewables. I'll try
3 to explain what this graph is designed to
4 represent. What staff did was assume that in the
5 event of increased of PGC funding, and a
6 corresponding impact on demand and the development
7 of renewable generation, the market would respond
8 by reducing the amount of gas fired capacity that
9 was built.
10 For each year here, 2005, 2008 and 2013
11 you see two columns. The dark blue entry is the
12 amount of gas fired capacity that staff assumed
13 would be added in California during that year. So
14 you can see from the first column staff assumed
15 about 2,700 megawatts being added in 2005.
16 When it developed the high PGC scenario,
17 it assumed that demand would fall slightly, as
18 indicated by the red entry in the second column,
19 and the market would respond by reducing the
20 amount of gas capacity it had at ever so slightly.
21 2005, the impact isn't very substantial,
22 but if you look at 2008, in our baseline studies,
23 we assume that a very small amount of gas fire
24 capacity would be added, about 200 megawatts. In
25 the high PGC scenario we assume that no gas prior

1 capacity would be added.

2 That peak loads would have fallen as a

3 result of demand site management by about 250

4 megawatts, and that about 80 megawatts of

5 renewable capacity would be added over and above

6 what would be added in the baseline case. The

7 baseline case of course met our PS targets.

8 This assumed that even more capacity

9 would be added. The figures are about 50 percent

10 higher. So in the baseline case, meeting the RPS

11 requirement assumes the additional of about 3,700

12 megawatts of renewable generation. In this case,

13 we added 50 percent more, or about 5,500

14 megawatts.

15 So and the results are somewhat

16 intriguing. We find that gas fire generation

17 falls by about seven and a half percent. What we

18 end up with the end is that renewables produce

19 about 9,200 gigawatt hours more generation. We

20 assume that the RPS will lead to about 18 or

21 19,000 gigawatt hours by 2013 of renewable

22 generation, above and beyond what existing

23 renewables will provide.

24 In this scenario it comes to a total of

25 about 27,000 gigawatt hours of renewables. Energy

1 consumption in the state, as a result of increase
2 DSM savings, fallen by about 10,000 gigawatt
3 hours. The total is 19,000 gigawatt hours. This
4 is almost all gas fired generation no longer being
5 necessary.
6 This is on a WCC wide basis. About half
7 that generation savings would take place in
8 California. So you look at a 10,000 gigawatt hour
9 reduction in the amount of generation from gas
10 fire capacity in California. It's about seven and
11 a half percent of the total.
12 And as the least efficient gas is being
13 displaced we see that gas use falls by about nine
14 percent among California generators. This will
15 have an effect on the natural gas price, which
16 back of the envelope said the assumptions means
17 that the natural gas price falls between one and
18 two percent resulting in additional savings of
19 California ratepayers.
20 So I believe that concludes my
21 presentation. There is nothing beyond this which
22 is reacted. So I will be -- either that or
23 everything is reacted. I'll be happy to take
24 questions. Judy Grau is going to discuss
25 transmission adequacy, transmission issues during

1 the next ten years.
2 So you can save questions until
3 afterwards, points of clarification.
4 MR. ALVARADO: Yeah. Judy, why don't
5 you give your presentation and maybe have you both
6 sit up over here and fuel any questions,
7 considering that you've given quite a bit of
8 material to digest there.
9 MS. GRAU: I don't have any amusing
10 slides to begin my presentation. Mine is more
11 boring. But anyway, can you all hear me? Yes. I
12 have to speak right into it, right?
13 MR. ALVARADO: Yes.
14 MS. GRAU: Okay.
15 PRESIDING MEMBER BOYD: Maybe you
16 learned as David got more comfortable and he begin
17 to turn more towards the audience --
18 MS. GRAU: All right.
19 PRESIDING MEMBER BOYD: -- that the mike
20 didn't work as well. So you kind of have to be
21 faced right at it to work all the time.
22 MS. GRAU: Okay. I'll do my best here.
23 Okay. I want to begin just by mentioning that
24 this presentation was a collaborative effort among
25 several people, include David Vidaver, as well as

1 Bob Strand, Don Kondoleon, Jim McCluskey, Mark
2 Hesters and myself. Most of them are here today,
3 so if you have any specific clarifying questions
4 that I can't respond to one of them hopefully will
5 jump up and help on that.
6 Okay. I have four major areas I want to
7 cover this morning. The first is an update on the
8 upgrades we assumed in the simulations. In
9 February we published the infrastructure
10 assumptions report. Some of these projects that
11 we are assuming have had some major rulings or
12 other things happen up to then and since then, so
13 I'll give a real update.
14 First, a little status of what projects
15 we assumed in February. And then an update on
16 each of them more specifically. And then talk
17 about some of the major obstacles to development
18 of transmission projects, what are some of the
19 things that are going on right now in the state,
20 as well as beyond the state to facilitate the
21 development of appropriate transmission resources.
22 And then finally, a little overview on
23 some additional on what staff is doing in this
24 IEPR cycle, as well as follow on update process
25 next year to hopefully do our best to bring -- to

1 continue facilitating the development of
2 resources.
3 Okay. So first of all, if you recall,
4 or if you had our February report, we had seven
5 projects that are large enough to be modeled in
6 the markets and model, which are folks up in the
7 engineering analysis office run. And so first let
8 me briefly go over each of these seven projects,
9 what they are.
10 And so I'll begin with pat 15. This
11 would add a third 500 killavolt line between Los
12 Banos and GATES. The actual cap is longer than
13 that, but the part that's constrained where there
14 are only two 500 KV lines instead of three is just
15 from Los Banos to GATES.
16 This is an economic project sponsored by
17 Trans-elect, and independent transmission
18 organization, and Wester Area Power
19 Administration, WAPA, and PG&E. And it's designed
20 to help relieve congestion on that path. And our
21 assumption in the February infrastructure
22 assumptions report was that this upgrade would
23 increase the cell to north rating from 3,900
24 megawatts to 5,400 megawatts, an increase of
25 1,5000 megawatts.

1 And in the north to south direction,
2 increase from 2,130 megawatts to 3,265 megawatts
3 in January of 2005. The path 26 upgrade is from
4 PG&E's midway substation to Southern California
5 Edison's Vincent Substation. And this upgrade
6 that we're referring to here is an operating
7 procedure change that would allow for an
8 additional 400 megawatts increase in transfer
9 capability to help relieve congestion on this
10 path.
11 And this is being accomplished by it's
12 starting a new remedial action scheme to drop new
13 generation in the midway area in the event of a
14 contingency. So it's not a reconductering. It's
15 not new lines. It's more an operating procedure
16 changes.
17 And our assumption in the February
18 report was that this upgrade would increase the
19 directional path rating from 3,000 to 3,400
20 megawatts in October 2003. The path 45 consists
21 of (indiscernible) from Mexico Comision Ferale de
22 Electricidad into San Diego Gas and Electric's
23 territory.
24 And the physical upgrades needed to
25 increase the south to north rating from 408

1 megawatts to 800 megawatts were accomplished in
2 November of 2001. But the WECC has not yet
3 improved the increase in the rating for the summer
4 months. And our assumption in the February report
5 was that this approval would occur by January
6 2003.
7 The fourth bullet there, the San Diego
8 Gas and Electric Migues to Mission upgrade, would
9 convert an existing 13869 KV line to a 230 KV
10 line. Included in this upgrade is the addition of
11 a second transformer at the San Diego Gas and
12 Electric Imperial Valley Substation.
13 Our assumption in the February report
14 was this economic upgrade would increase the
15 transfer capability into Downtown San Diego from
16 1,690 megawatts to 2,250 megawatts as of January
17 2005. This is a total increase of 560 megawatts.
18 The staff is assuming that the
19 transmission upgrade of the southern portion of
20 5.6 will be necessary in the future in order to
21 accommodate possible future geothermal development
22 in the Salton Sea area that may respond to the
23 renewable portfolio standard program.
24 Our section in the February report was
25 this project would increase the path rating

1 between the Imperial Irrigation District and
2 Southern California Edison by directionally from
3 600 megawatts to 1,600 megawatts for an increase
4 of 1,000 megawatts as of January 2009.
5 The sixth project, Jefferson-Martin is
6 one that David Vidaver has mentioned in a couple
7 of different context in the San Francisco area
8 being the liability constraint. This is a new 230
9 KV line proposed by PG&E, as he mentioned, for
10 reliability purposes, unlike many of the other
11 projects, which are primarily economic projects to
12 relieve congestion.
13 PG&E filed for a certificate of public
14 convenience and necessity, a CPCN, with the PUC on
15 September 30th, 2002. Our assumption in the
16 February report was that this new line would
17 increase the transfer capability from the north of
18 path 15 area into the City of San Francisco from
19 700 megawatts to 1,100 megawatts as of January
20 2006 for an increase of 400 megawatts.
21 And finally, the Valley Rainbow Project
22 would be a new 500 KV line connecting to Southern
23 California Edison's existing substation with a new
24 San Diego Gas an Electric Rainbow Substation. Our
25 assumption in the February report was that this

1 project would increase the San Diego Gas and
2 Electric to Southern California Edison path rating
3 from 700 to 1,450 megawatts.
4 And in the other direction from SCE to
5 SDG&E, path rating from 200 megawatts to 2,950
6 megawatts as of January 2009. Okay. This slide
7 shows the market how the transmission system is
8 modeled. Okay. And I'll attempt to show these
9 with a little pointer here starting at the top.
10 The Jefferson-Martin line would be
11 modeled as going between north at path 15 and the
12 San Francisco area. The numbers here indicate 700
13 megawatts. It's the current transfer capability.
14 And then the second number is the increase with
15 the month and year that that would take effect.
16 So path 15 -- I'm sorry, Jefferson-
17 Martin is between here and here. North of path 15
18 to zonal path 26 would be the path 15 upgrade, as
19 we discussed between zonal path 26 and Southern
20 California Edison is path 26, which is the midway
21 to Vincent. From Southern California Edison to
22 San Diego Gas and Electric would be the Valley
23 Rainbow new connection.
24 From Southern California Edison to IID
25 is the 1,000 megawatts we are assuming needed to

1 bring new generation that may respond to the RPS
2 program, the new thermal in the Salton Sea to
3 connect that. And then from Southern -- I'm
4 sorry, San Diego Gas and Electric down to Miguel
5 would the Mission Miguel Project.
6 And then finally path 45 is the two
7 lines connecting the major areas in Mexico up to
8 across the border, San Diego. And we split the
9 800 megawatts, 400 here and 400 here just for
10 simplicity. Okay.
11 So now that we're familiar with the
12 seven major projects, I want to give an update on
13 what has happened since our infrastructure
14 substance report in February. Beginning with path
15 15, the first bullet is just repeating what I
16 already said. So I won't mention that.
17 The current status though is on May
18 22nd, of this year the PUC voted to allow PG&E to
19 withdraw its CPCN application, and that also
20 approved the final supplemental environmental
21 impact report as the environmental impact report
22 for the project. And so between these two actions
23 it allows PG&E to proceed with the project under
24 federal authority with its partners, Trans Elect
25 and the Western Area of Power Administration,

1 WAPA.

2 And Morteza Sabet Sava of WAPA is here

3 today, and he can give you more details on the

4 status of the project if you would like after the

5 formal presentation. Just in brief, they've now

6 chosen a contractor and the project is moving

7 forward. Morteza can tell you more about that.

8 Okay. On path 26, as I mentioned, this

9 is a remedial scheme upgrade primarily, and the

10 timing of it had not been affected by the March

11 21st, Vincent Substation fire. Some of you may

12 know there was an explosion and fire at Southern

13 California Edison's Vincent Substation,

14 transformer bank number two.

15 They had three transformers there.

16 Number two was irreplaceably damaged. So as a

17 result, the current transfer capability for the

18 two working transformers is currently limited to

19 2,500 megawatts. But a fourth transformer had

20 already been planned for the Vincent Substation.

21 So now its installation is being

22 expedited. And that will allow a return to the

23 3,000 megawatt rating in July. And then the

24 remedial action scheme upgrade would then bring

25 the rating up to 3,400 megawatts.

1 The predicted on line date for that now
2 is November 2003. So in terms of that, there's no
3 modeling impact because their simulation doesn't
4 become -- doesn't begin until January 2004. So
5 we're still on schedule from that respect. Okay.
6 On path 45, we had said back in February that the
7 CC approval would already have occurred, or been
8 imminent.
9 It's now expected to occur in mid July
10 of this year. And, again, the modeling impact is
11 none because we don't begin our simulations until
12 January 2004. On a related note though, there was
13 a May 3rd, ruling by Judge Gonzalez who wrote that
14 the DOE and Bureau of Land Management violated the
15 National Environmental Policy Act by failing to
16 fully recognize the potential error of water
17 quality impacts when it approved the permits for
18 the construction and operation of transmission
19 lines linking two new power plans in Mexicalli,
20 Mexico.
21 One is Sempra 600 megawatts, Electra de
22 Mexicalli Plant. And the other is Intergen 560
23 megawatt La Rosita Plant. And these connect
24 directly to the grid in Imperial County, although
25 the power plants are located in Mexico.

1 And the court has scheduled a June 16th,
2 hearing for the remedy portion of this case, which
3 will determine what the DOE needs to do to comply
4 with NEPA and the court ruling. And on June 4th,
5 the group of cross border residence and health
6 organizations and environmental groups asked the
7 judge to halt imports to California from these
8 plants.
9 I'm not sure if La Rosita is up and
10 running, but I know that Termo Electrica de
11 Mexicali Plant, the Sempra Plant, has been up and
12 running and had been providing power. And so
13 Judge Gonzales is supposed to rule any day now on
14 the temporary restraining order.
15 Okay. On the Miguel Mission, the day
16 after we gave our presentation back in February,
17 the PUC approved the Miguel Mission upgrade and
18 the Imperial Valley Substation modifications, and
19 found that both projects are economic and in the
20 public interest.
21 A CPCN is not required for the Imperial
22 Valley modifications, but is needed for the Miguel
23 Mission upgrade. Although the PUC said they would
24 expedite that process. And that decision also set
25 a cost cap of 55.4 million dollars for both the

1 Imperial Valley upgrades and the Mission Miguel
2 upgrades.
3 Path 46, this is our generic assumption
4 to bring increased renewables from the Salton Sea
5 area out in the Imperial Irrigation District area.
6 We're not changing that assumption. So that's
7 still valid. And on Jefferson-Martin, on March
8 19th, the administrative law judge at least a
9 scoping memo of ruling, and it basically sets the
10 scope for the project.
11 It includes PG&E's preferred route,
12 alternative routes, the no project alternative,
13 and non wires alternatives. And it also set a
14 schedule for release of a draft environmental
15 impact report in July 2003. And evidentiary
16 hearings in December of 2003, and a decision in
17 May 2003.
18 So our modeling impact, we have the
19 project coming on line January 2006. And we
20 believe that's still feasible based on that
21 schedule, assuming a positive finding. Valley
22 Rainbow just, what, five days ago, at the PUC's
23 business meeting, they voted against on split
24 decision San Diego's Gas and Electric's petition
25 for modification.

1 So what that means is that San Diego Gas
2 and Electric cannot reopen the case unless they
3 start over with a new application. At this point,
4 San Diego Gas and Electric has not publicly
5 announced its plans, and I'm not sure if there's
6 anyone here who would like to speak further on the
7 issue.
8 But we just want to note that the
9 project is included in San Diego Gas and
10 Electric's 20-year electric resource plan that was
11 filed with the PUC on April 15th. And they call
12 that project the near term interconnection
13 project. And it's part of a larger plan to
14 improve the backbone of the 500 KV system in the
15 area.
16 And as they note in the 20-year plan,
17 the soonest that short -- the near term
18 interconnection project, which is essentially
19 Valley Rainbow, the soonest that project could be
20 built is 2008. And our assumption has been, and
21 is, January 2009.
22 Okay. I want to switch now from
23 modeling impacts to some of the obstacles, to the
24 development of transmission projects. We've kind
25 of grouped in three major areas, planning,

1 permitting and financial. And beginning with
2 planning, we believe that the state's perspective
3 is often not adequately incorporated into
4 transmission planning activities.
5 And so the broad principles and interest
6 of the state are not always considered, such as
7 efficient use of the existing system and rights of
8 way. And these are what we call the Garamendi
9 principles that we've been advocating for many
10 years.
11 Also, long-term strategic expansion of
12 the system may not be adequately considered,
13 planning for future right of way needs and
14 balancing the environmental goals with system
15 reliability and economic needs of the state. With
16 respect to the permitting process, their
17 permitting processes for various types of
18 transmission projects are often fragmented and
19 overlapping.
20 An environmental analysis are sometimes
21 inconsistent and, as we mentioned, state wide
22 benefits may not be adequately considered. The
23 PUC's CPCN process, certificate of public consumes
24 and necessity, looks at the economic need for the
25 project within the context of ratepayer benefits.

1

2 And thus, the strategic benefits of a
3 project may not be adequately addressed. Such
4 strategic benefits maybe regional or statewide in
5 nature. Whereas, we also recognize the physical
6 impacts of this project are local. So as a result
7 there's often strong local opposition to
8 transmission projects because of concerns about
9 visual, environmental or property value impacts.
10 For the financial side, private
11 investment and transmission has been slowed by the
12 financial distress of some developers, as well as
13 regulatory and economic uncertainty. The next two
14 slides talk a little bit about some of the actions
15 being taken by the state and others to facilitate
16 the development of transmission resources.
17 Beginning of course with our SB1389
18 mandate, which provides a mechanism for the Energy
19 Commission to corroborate with appropriate state
20 and federal agencies, and encourage cooperation
21 among state agencies that have energy
22 responsibilities.
23 And this mandate states that the results
24 of the Energy Commission analysis shall be made
25 available to such agencies in order to provide a

1 common basis for decisions. This state energy
2 action plan has recently been adopted by the three
3 collaborating entities, the Energy Commission, the
4 Public Utilities Commission, and the California
5 Power Authority.
6 And it contains the goal. It explicitly
7 states the state will reinvigorate its planning,
8 permitting and funding process to assure that
9 necessary improvements and expansions to the bolt
10 electricity grid on made on a timely basis.
11 So, again, the planning, permitting and
12 funding processes, those are the major obstacles I
13 just had in my last slide. So it's kind of a
14 validation of those three major areas. And one of
15 the action items for achieving this goal is to
16 explicitly require the agencies to participate in
17 the Energy Commission's Integrated Planning
18 process to determine the statewide need for a
19 particular bolt transmission projects.
20 The IEPR update process, the third
21 bullet, I'll be talking more about that on the
22 last two slides. But right now I just want to say
23 that SB 1389, if you look at section 25302D,
24 provides for an off year update due November 1st,
25 2004, a year from now.

1 That provides for policy review, as well
2 as an opportunity for raising new issues that have
3 emerged since the release of our plant, November
4 2003 report. Okay. The next group of items,
5 beginning common analytical tools, those of you
6 who are the PUC's investigation 00-11-001, it's a
7 multi-phase transmission constraint related
8 proceeding.
9 And phase V of that proceeding is
10 looking at the development of a generic
11 methodology for evaluating the economic need for
12 transmission upgrades. The California ISO, who I
13 believe is here today, Robert Sparks, yeah, maybe
14 can talk more about that.
15 But they've been working with London
16 Economics International on a generic methodology.
17 They issues a draft report in the end of February.
18 However, since that time it's become apparent that
19 the ISO needs more time to more fully develop and
20 apply the methodology. And it may take up to a
21 year for the ISO to validate the methodology.
22 And on April 10th, of this year the ALJ
23 Gottstein ruled that this phase of the proceeding
24 would be deferred until the ISO has validated the
25 network. And until the ISO and/or other

1 respondents have completed a study, using the
2 proposed methodology on a specific high priority
3 transmission project.
4 With the respect to strategic long-term
5 planning, the Energy Commission and the ISO have
6 initiated an effort to ensure that long-term
7 planning and strategic project benefits are
8 included in the state's IEPR process, and in the
9 ISO's transmission planning process.
10 With respect to vocational marginal
11 pricing, in late May the ISO made public its
12 revised draft proposal for market redesign, and it
13 includes provisions for creating a day ahead, an
14 hour ahead, markets that operate on location
15 marginal pricing.
16 And this would create I believe it's
17 like 3,000 notes in California, as opposed to the
18 current system, the Zonal approach, which relies
19 on just three zones in California. So this would
20 provide by having more notes, more transparent
21 knowledge of where the constraints are, and give
22 the signals to developers, generation or
23 transmission, of where they could they could most
24 benefit the system.
25 And finally, FERC incentives, the

1 Federal Energy Regulatory Commission is
2 encouraging public utilities to join regional
3 transmission organizations, or form independent
4 transmission companies, and is providing a return
5 on equity incentive for those who do so.
6 The last thing I want to talk about is
7 staff's transmission study plan and white paper.
8 What we're trying to do is conduct a preliminary
9 analysis, a representative transmission projects
10 to determine if there are statewide benefits.
11 And we believe this analysis response to
12 our mandate to assess the availability,
13 reliability and efficiency of the Western Regional
14 and California Transmission system. And also the
15 response to the recently adopted state energy
16 action plan, which asks the agency, including the
17 ISO, to work together to ensure that state
18 objective are evaluated and balanced, and
19 determined in transmission investment that best
20 meet the needs of Californians.
21 We are going to publish a white paper
22 July 25th, which is concurrent with our
23 electricity and natural gas report. And we also
24 have plans for future work, as I mentioned, in the
25 update cycle, which is the off year report due

1 November 2004.
2 And so in case none of you were able to
3 figure it out because we didn't mention the names
4 in the infrastructure assessment report, we just
5 called them a major interstate economic project,
6 that would be the second Palo Verdes DEVERS line.
7 The major interest rate intra-utility
8 project is the Valley Rainbow Project. The
9 intra-utility reliability project is PG&E
10 Jefferson-Martin Project. And the intra-utility
11 RPS project is Tehachapi.
12 And so for each of these projects we
13 will be performing a recognizance level economic
14 and/or qualitative assessment of the benefits
15 using our in-house technical expertise. So the
16 results of these analysis will be contained in our
17 white paper. We've preliminary entitled it
18 California's Electric's Transmission System Issues
19 and Solutions, or something like that.
20 As I mentioned it, we're going to
21 release it concurrent with the electricity and
22 natural gas report on July 25th. And in the white
23 paper we're also going to identify the potential
24 critical issues associated with each of these
25 projects. And provide direction on what staff

1 would like to accomplish in the next 12 months or
2 so in the IPER update process.
3 And we'll also update the reader of the
4 status of the most noteworthy actions being taken
5 to facilitate the development of transmission
6 resources, the seven bullets where we just talked
7 about the actions being taken by the state and
8 others.
9 So that concludes my presentation. I
10 will turn it back over to Al for the moment.
11 He'll tell us what we're going to do next.
12 MR. ALVARADO: Well, Commissioners, I
13 was going to suggest taking a ten minute break
14 before we open up to any questions or comments
15 that we may have from the public. So I suggest,
16 let's say, we reconvene at ten after 11:00.
17 PRESIDING MEMBER BOYD: Five after.
18 MR. ALVARADO: Let's make it five after
19 11:00.
20 (Off the record.)
21 MR. SABET: Good morning. I'm Morteza
22 Sabet of Western Area Power. Basically, we are on
23 our way. And based on what I got yesterday, we
24 have about two-thirds of a right away acquired,
25 and about three-fourths of an access road for

1 construction maintenance, also done.
2 And hoping to start the construction
3 this summer and be done by fall of 2004.
4 Hopefully before the original date that we
5 forecasted, December of 2004. And I trust PG&E's
6 portion, I was told that is going to be done at
7 the same time.
8 So the project will energized late 2004.
9 So anything else?
10 PRESIDING MEMBER BOYD: No. Well, this
11 is a question for our staff, and maybe for you,
12 I'm not sure. It's almost not relevant, but I
13 don't a form like this on transmission very often.
14 I believe you recall that in the summer of 2001
15 there was an effort to fix path 15.
16 It was aborted by, what I thought at the
17 time, unilateral action of the PUC to order PG&E
18 to fix path 15. I'm just wondering, I've never
19 had a good explanation, and I don't know if I want
20 one in public today, but I'm still going to be
21 seeking an explanation from our staff of, you
22 know, why that crashed and burned, and is the
23 current solution a better solution than the
24 solution that was being pursued in 2001?
25 Because, frankly, the deadline then was

1 to have this thing up and running in 2000, or at
2 the beginning of 2004, end of 2003. And to me,
3 we've lost a lot of time.
4 MR. SABET: I was a witness in that
5 area, but I take the fifth on that one.
6 PRESIDING MEMBER BOYD: Yeah. Okay. I
7 think a lot of people have for a long time. So
8 I'll just put our staff on notice that one of
9 these days in the privacy of my office I'd like to
10 have a little chit chat.
11 MR. SABET: Thank you.
12 CHAIRMAN KEESE: I'd like to ask with
13 regard to the transmission, we had -- you had
14 listed seven projects. Is it staff's position
15 that all seven of those projects are needed?
16 MS. GRAU: Well, okay, in terms of need,
17 we're not going to comment I think on the ones
18 that are going through the CPCN process. But
19 there's reliability need and there's economic
20 need. And in terms of the reliability need, I
21 think -- again, I don't want to put words in other
22 staff's mouth but, you know, we have staff who
23 look at the -- specialize in the San Francisco
24 area.
25 And from a reliability standpoint, and I

1 think Dave mentioned also, Jefferson-Martin, if
2 it's not built, there will be a problem beginning
3 in is it 2004 or 2005?
4 CHAIRMAN KEESE: That's my next question
5 then, because I heard Jefferson-Martin in 2006.
6 MS. GRAU: That's our staff assumption
7 was that it would be built and on line by then.
8 But I think the schedule for the CPCN -- I forgot
9 what I said in my slides, but they're not even
10 going to make a decision until -- I'm sorry, I
11 lost my train of thought.
12 CHAIRMAN KEESE: So I accept to the 2006
13 as --
14 MS. GRAU: May of 2004. So the soonest
15 we can come out to be built after that process.
16 So we assume January 2006.
17 CHAIRMAN KEESE: And is that enough to
18 meet the reliability needs in San Francisco? It
19 seems to me that the reliability needs in San
20 Francisco are current.
21 MS. GRAU: Yes. When did you believe
22 that -- you said (indiscernible) and what not
23 would occur.
24 MR. VIDAVER: I may have illusion to the
25 possibility that there would be curtailments in

1 San Francisco. San Francisco is just a series of
2 very, very old plants with very, very high outage
3 rates. So when you simulate what happens there
4 occasionally you get two or three of those plants
5 going down and you can't keep the lights on.
6 CHAIRMAN KEESE: So it could happen
7 anytime now, and the earliest that Jefferson-
8 Martin can come on is 2006?
9 MR.VIDAVER: We would generally agree
10 that there maybe -- it's not an unreasonable
11 possibility that you'd have to turn the lights out
12 in San Francisco. We came very close I believe it
13 was in December of 2001 to that happening. I
14 remember all of us sort of watching what was going
15 on.
16 And had one even small GT tripped in San
17 Francisco, the lights were going out.
18 CHAIRMAN KEESE: With respect to Valley
19 Rainbow, and I'm trying to avoid appropriateness,
20 you know, whether that line as proportionate
21 built, that it seems to me that is the other one
22 you put in the reliability category.
23 MS. GRAU: I believe when it was filed
24 with the PUC it was couched as a reliability
25 project. But like a lot of projects, they're both

1 reliability and economic sides to most projects.
2 And I believe now they classify it as an economic
3 project.
4 CHAIRMAN KEESE: And so we didn't make a
5 judgement that something like that is needed for
6 reliability, independent probably of that process?
7 MS. GRAU: No, not for reliability
8 purposes. What it is is it has the opportunity to
9 reduce R&R contracts in the area. And, you know,
10 I'm going to let Mark Hesters bail me out on this
11 one.
12 MR. HESTERS: When we were making these
13 assumptions about transmission lines for this
14 model, they're not -- I just wanted to be clear,
15 they're not an endorsement of the project.
16 They're more of a -- you have to make a planning
17 assumption that something is going to happen.
18 You can assume nothing happens, and that
19 could be right, but it's probably going to be
20 wrong. And we just decided that we thought
21 something was needed in San Diego, and that
22 Rainbow Valley was a pretty reasonable assumption
23 for something that was going to happen.
24 Whether it's exactly Rainbow Valley or
25 it's something completely different, Rainbow

1 Valley is the best sort of picture that we have so
2 far. And that's where that comes from.
3 CHAIRMAN KEESE: So to characterize the
4 seven that were on your list, starting with path
5 15, those are the ones that are in the ISO
6 planning perspective, the planning perspective,
7 the Energy Commission planning perspective. Those
8 are the seven chief projects that are being
9 discussed, is that --
10 MS. GRAU: Yes, but within the context
11 of how they are modeled in Henwood. For example,
12 Tehachapi you notice we didn't talk about that in
13 there because that, within the notes, that
14 diagram, that very complicated diagram, I showed
15 some projects are within a note, and so they do
16 not show up.
17 So these are major intra-noble from the
18 standpoint of the Henwood Markinson model. These
19 are the major ones that we believe will --
20 CHAIRMAN KEESE: That we discussed.
21 MS. GRAU: That we are assuming will be
22 built, yes. Yes.
23 CHAIRMAN KEESE: We're not making a
24 determination. We're saying these are on the
25 horizon.

1 MS. GRAU: No, these are just for
2 planning assumptions. These are the ones we are
3 assuming in those time frames.
4 PRESIDING MEMBER BOYD: Because Valley
5 Rainbow was just referenced in that it's off the
6 table now as of June 5th, do you have a hole in
7 your analysis? I mean you assume something.
8 We're not endorsing specific projects. You assume
9 something in San Diego. This was the Bible
10 candidate. Now, there's a black hole there in my
11 mind. What does that do to your assumption?
12 MS. GRAU: Well, I think just carrying
13 on with what Mark Hesters said, for planning
14 assumptions, we need to assume something. And as
15 I also mentioned, in San Diego's 20-year plan,
16 they now show that Valley Rainbow Project is part
17 of a larger backbone improvement project that
18 would actually connect from the existing Southern
19 California Edison Valley Substation down to a new
20 Rainbow Substation in San Diego's territory, and
21 then further connecting that new Rainbow
22 Substation over to Imperial Irrigation, Imperial
23 Valley Substation.
24 So it would make a ring around that
25 completes the loop. And so in the 20-year plan

1 that's a vital part of their plan.
2 PRESIDING MEMBER BOYD: Don, why don't
3 you step up. Okay.
4 MR. KONDOLEON: Yeah. Commissioner,
5 Boyd, this is Don Kondoleon again with the Energy
6 Commission staff. A number, of course, as Judy
7 alluded to at the presentation, we're going to be
8 doing an evaluation of four projects, one of those
9 was included in the Valley Rainbow Project.
10 So we will be doing an examination of
11 the benefits of that project, irrespective of the
12 decisions that were made over in San Francisco. I
13 think we still believe that that project has
14 portrayed in the 20-year plan for San Diego, makes
15 some sense, especially one done in conjunction
16 with other projects.
17 And I think that's how the projects are
18 portrayed now by San Diego Gas and Electric. I
19 think one of the issues with regard to the Valley
20 Rainbow Project in the information that was
21 presented in the CPCN is that a project was
22 presented in isolated. When in isolation it's
23 difficult to necessarily measure the benefits from
24 that project.
25 I think when you're looking at a

1 conjunction to other additions to the system, you
2 can start to see the value of increasing transport
3 capability, both into San Diego, and also the
4 ability to transport power from San Diego to the
5 north once you've got that highway down to Mexico
6 and are able to access that strand of generation
7 that now exists south of the border.
8 So those are the sorts of things we want
9 to try to do in the IEPR process and the update
10 process here at the Commission, using our own
11 tools and working closely with ISO staff and the
12 utilities.
13 MS. GRAU: May I just add one more
14 point, in the Valley Rainbow decision to deny it,
15 they were only looking at a five-year time
16 horizon. And they said the project was not needed
17 until at least 2008. And so by denying it,
18 they're not denying it categorically forever.
19 It's just within the time frame. And so
20 we did not assume it would be on line until
21 January 2009. There is still a possibility that
22 San Diego could refile such a project. And it
23 could be found needed, you know, in a later time
24 horizon.
25 CHAIRMAN KEESE: I was going to follow

1 up on your suggestion and ask if there does happen
2 to be anybody from San Diego here who would feel
3 that they could comment on this and tell us if
4 there is a plan by San Diego at this time?
5 MR. BING: I'm Chris Bing, regulatory
6 affairs, of course, San Diego Gas and Electric.
7 You know, this isn't a project that I'm assigned
8 to at Valley Rainbow, but I do know that at this
9 point there has not been a decision made as to
10 whether SDG will refile.
11 And as far as when that decision is
12 going to come, I really don't know, but we can
13 keep in contact with Commission staff and advise
14 you as soon as it happens.
15 CHAIRMAN KEESE: Thank you.
16 MR. ALVARADO: If you have a business
17 card to provide, our court reporter, he would
18 appreciate that. Thanks.
19 CHAIRMAN KEESE: That's the end of my
20 questions.
21 PRESIDING MEMBER BOYD: I have no more.
22 MR. ALVARADO: I was wondering, while
23 we're on the topic of transmission, I know that
24 the California ISO is here, and I believe,
25 Mr. Sparks, did you have some comments while we're

1 on the topic of some transmission issues?
2 MR. SPARKS: Sure, should I --
3 MR. ALVARADO: Yes, please come up.
4 MR. SPARKS: (Inaudible) that Don asked
5 me to prepare or think about. Did you want me to
6 try and address the questions that you were
7 asking? I have sort of have a little canned
8 comments here. I'll just go through them. Maybe
9 I can touch on them, potential Valley Rainbow
10 impacts.
11 I'm Robert Sparks from the California
12 ISO. I just wanted to point out that the
13 California ISO is participating in the SSG-WI
14 process, the RTO scene steering group, Western
15 Interconnect process. SSG-WI will be performing
16 at WECC wide long-term transmission study.
17 And the ISO will be submitting projects
18 to the SSG-WI process for them to evaluate in
19 their study. These ISO projects, or the ISO will
20 develop these projects with groups of stake
21 holders through the STEP study process, which is
22 the southwest transmission expansion planning, or
23 plan process, which is a rigorous study that's
24 currently ongoing to analyze transmission projects
25 between the southwest and Southern California, or

1 Arizona, Southern Nevada, New Mexico, and Southern
2 California.
3 The ISO is also working on an
4 abbreviated assessment of the transmission system
5 between the northwest and California, and within
6 California to possibly identify additional
7 projects to submit to the SSG-WI project for their
8 analysis.
9 And we are working with, and following
10 along, in the IEPR process, and trying to
11 integrate with all the various processes. A
12 couple questions came up, one was on the London
13 economics methodology. The ISO is working with a
14 vendor on developing a detailed network model that
15 would be compatible with that vendor's market
16 simulation package.
17 And that is currently the delay. I
18 think it was referred to earlier in discussing I
19 think it's even called the phase V CPUC AB970
20 process. But in the interim we are using the
21 ABB's market simulation, or market simulator
22 package, for both the SSG-WI and the STEP
23 analysis.
24 And as far as Valley Rainbow goes, I
25 think it's anticipated that the STEP may provide a

1 long-term plan, which could show the benefits of
2 the ring that Judy talked about, connecting
3 Imperial Valley to Rainbow and eventually Imperial
4 Valley Substation. That is in Imperial County.
5 To Rainbow and then to Valley. And that
6 may -- I mean there's Victor looking at about 16
7 different alternatives. It's quite a number, but
8 hopefully they'll come up with a short list. But
9 those projects are certainly part of the various
10 alternatives that they're going through quickly.
11 In September they hope to have a short
12 list to present to SSG-WI for the analysis. So
13 that's all I had. I did have one question since
14 I'm here. The four projects that will be
15 analyzed, one of them was Tehachapi. And I think
16 earlier it was said that an analysis of the
17 benefits of these projects will be performed.
18 And my question is, is there -- what
19 exactly which Tehachapi -- what does the scope of
20 the Tehachapi project that would be analyzed?
21 MR. HESTERS: The Tehachapi project that
22 we're analyzing is less of a transmission
23 analysis, and more of a value of wind analysis.
24 It sort of starts with the assumption that enough
25 transmission is going to be built to get sort of

1 the maximum amount of wind out of Tehachapi, and
2 goes from there.
3 And so essentially we simplified it to a
4 single 230 KV substation with a lot of wind, and
5 then lines feeding that, feeding (indiscernible).
6 Does that answer your question?
7 MR. SPARKS: Yeah, yeah.
8 MR. HESTERS: Okay.
9 MR. SPARKS: It's essentially assuming a
10 simplified type project, but not a detailed
11 analysis of I guess the impacts of that project on
12 the rest of the grid or -- the reason I ask is the
13 ISO has presented some testimony in phase VI of
14 the CPUC AB970 process recommending that other
15 alternatives will at least be analyzed, that could
16 be electrically substantially different than just
17 a radio line.
18 But anyway, it's just a question. We
19 can talk about --
20 MR. HESTERS: We knew about those
21 alternatives, but we didn't have enough
22 information to model them very well. And decided
23 that rather than try and make a wild guess we
24 would just start with the assumption that anything
25 that is built is going to be big enough to get the

1 wind out and go from there.

2 MR. SPARKS: Yeah. I think it's the one

3 concern maybe, and I maybe speaking only for

4 myself, would be that a conclusion has come up

5 that it's not economic to build the transmission

6 when not all of the alternatives have been looked

7 at yet.

8 CHAIRMAN KEESE: Since I have both you

9 and staff here, what is the assumption with regard

10 to Mexican generation? Are you assuming that the

11 current plants that are either on line or on line

12 next week is what's feeding in? Or are you making

13 any assumptions with regard to additional

14 generation forces in Mexico that would impact the

15 transmission plant here?

16 UNIDENTIFIED MALE: I am not

17 participating directly in the STEP process. I'm

18 more the northern guy at the ISO. I defer that

19 question back to the panel.

20 MR. HESTERS: We're using two different

21 modeling systems, and keeping the assumptions

22 consistent. I don't have it sitting right in

23 front of me, which plants we've assumed on line.

24 We've assumed the ones that are built are going to

25 be operating.

1 CHAIRMAN KEESE: But, you know, you're
2 now making an assumption about major expansion of
3 Mexican generation on how it could be
4 accommodated.
5 MR. VIDAVER: No, I don't know the
6 number off the top of my head, but I don't believe
7 that it's substantial, that we add something on
8 the order of maybe 600 megawatts. And to be
9 honest, I don't remember whether we had it at La
10 Rosita or in Tijuana.
11 CHAIRMAN KEESE: I was just thinking of
12 some of the proposals. Some of the L&G proposals
13 suggest major transmission going across I believe
14 to Aron Bery. Not coming to San Diego, but
15 heading over to the Arizona, California border.
16 That's not in the plans?
17 MR. VIDAVER: No, we haven't modeled the
18 scenario like that, no.
19 PRESIDING MEMBER BOYD: I want to go
20 back to Tehachapi for just a moment. I don't want
21 to put anybody on the spot, but it's not too often
22 we get an opportunity to discuss these things.
23 And I understood the discussion.
24 But when it comes down to, you know,
25 policy issues, which is what part of the November

1 report is all about, you know, Commissioners sit
2 around in hearings on occasion and told repeatedly
3 that the Tehachapi link is a very weak link, and
4 it's prohibiting desirable development of wind in
5 the area.
6 And then I hear this discussion about
7 assumptions made and not made, and alternatives
8 need to be looked at. It doesn't make me feel
9 real warm and fuzzy about there's a solution to
10 the alleged problem in the Tehachapi area
11 forthcoming in the immediate future.
12 And Tehachapi has been talked about as a
13 problem to me long before I even came to work here
14 at the Commission. So, again, it seems to be
15 another one of those that just goes on, and on and
16 on. And maybe I'm wrong, but somewhere in this
17 process I would like to get a handle on is there a
18 policy issue here or isn't there?
19 Are things being handled expeditiously
20 in that area? And now I hear a new discussion of
21 a need to look at alternatives, which is fine.
22 But where's the bottom line, you know? When do we
23 finally get to some decision that either, you
24 know, we're not going to develop anymore wind in
25 the area because it's not the right thing to do.

1 Or we are and we need transmission, or we need
2 something, you know.
3 And it's going to get in the cue and get
4 done. I mean life does not slow down. It's the
5 ever accelerating pace of everything, which goes
6 back to my mild impatience with path 15 taking
7 longer than what I was told it would take,
8 etcetera, etcetera.
9 So Tehachapi is another one just seems
10 to sit there forever and ever. I don't know if
11 you have any additional responses today, but it is
12 to me, quote, a policy issue that doesn't seem to
13 get resolved at the --
14 MS. GRAU: Okay. Go ahead.
15 MR. KONDOLEON: Well, you know, I've
16 been involved in this too, as you know,
17 Commissioner Boyd, since way back when with the
18 green team that we looked at the --
19 PRESIDING MEMBER BOYD: You should have
20 more white hair than I.
21 MR. KONDOLEON: I'm working on it. But
22 as you well know, there's been an issue for a
23 number of years between the developers and the
24 incumbent utility. Edison and developers had
25 problems for many years. And one of the things I

1 think we were able to accomplish through the green
2 team was finally to get parties to work together
3 and look at, and it led to development of these
4 conceptual studies, as referred to by Mr. Sparks.
5 Basically what's happened has been a
6 look at what possibly would be needed to support
7 maximum amount of wind development in the
8 Tehachapi region. And I think we're talking on
9 the order of two to 3,000 megawatts. And what was
10 developed in the second conceptual study was, you
11 know, sort of a preliminary examination of options
12 with regard to construction of I think up to four
13 230 KV substations, a number of feeder lines, and
14 one new 230 line.
15 And that was proposed by Edison and the
16 developers. The ISO then sort of took a look at
17 it and made some suggestions I believe, including
18 maybe potentially interconnecting to PG&E's system
19 as opposed to just running it through Edison's
20 system.
21 The bottom line is, again, it's sort of
22 two issues, one is the existing problem, which is
23 the inability of the existing system really to
24 support more than about 325 megawatts I believe is
25 the number of generation because of the 6669 KV

1 system that it currently transports, most of that
2 power into the Edison network.
3 And then the second thing is looking at,
4 again, at this potential for RPS development up to
5 2,000 to 3,000 megawatts and the need for
6 expansion of facilities. And what we've tried to
7 do here at staff level, as Mark talked about
8 earlier, was, you know, looking at the time frame
9 we had for analysis.
10 What could we do using our tools in a
11 short time frame to try to provide some input into
12 the potential value. And what we did is, again,
13 kind of do a simplified network of fix, which was
14 sort of look at what was proposed by the team,
15 which included Edison and developers, look at the
16 (indiscernible) that the ISO provided.
17 And then looking, again, on our own
18 constraints using our own tools, and manpower and
19 stuff, and came up with the idea that, well, we'll
20 just kind of do this as simplicity fix, at least
21 for the short-term. And really, as I say, as Mark
22 alluded to, it really comes to an examination of
23 really what the potential benefits would be of the
24 wind generation at this point, absent having any
25 capability to do the detailed studies.

1 What we've talked about potentially
2 doing in the IEPR updates cycle, you know,
3 starting next year, if in fact the Commission
4 feels strongly about us proceeding, I think then
5 we'd get into the more detailed assessments that
6 are necessary to really assess the value of that
7 sort of interconnection.
8 And I'm talking about the number of
9 projects and substations that are involved. But,
10 again, I think more than likely we're probably a
11 ways away from doing that, given the that fact, as
12 we said, that the ISO is sort of looking at things
13 a little bit differently than what the team had up
14 to this point.
15 And I don't think we're at the position
16 right now to say one is better than the other. As
17 I said, what we tried to do in our process here
18 now is to work cooperatively with ISO and the
19 utilities to try to reach, you know, solutions
20 that we think are in the best interest of the
21 state.
22 PRESIDING MEMBER BOYD: Thank you.
23 MR. ALVARADO: Thank you, Don. We've
24 definitely covered a whole spectrum of different
25 issues today. We've talked about short-term

1 outlook for our supply adequacy. David has also
2 talked about the long-term evaluation or different
3 scenario studies. What we're seeking here, if you
4 have any clarifying questions or comments, not
5 just what was discussed today, but the content of
6 the report itself.
7 CHAIRMAN KEESE: We have an impressive
8 audience.
9 PRESIDING MEMBER BOYD: It's time we
10 start hearing from the public.
11 MR. KELLY: Good morning, Commissioners,
12 staff. Steven Kelly with the Independent Energy
13 Producers Association. And since there doesn't
14 seem to be a rush of a billion people to come up
15 here, maybe I'll take the liberty of taking some
16 time. What I'd like to do if I could is I'm going
17 to step back to the 40,000 foot level and just
18 address, you know, my initial kind of personal
19 impressions about where we are in the planning
20 process an so forth.
21 And then maybe move to get into some
22 specifics about the report itself, provide perhaps
23 some recommendations on how they might be improved
24 for stake holders such as myself, or outside the
25 Commission. Looking at these reports on a daily

1 basis, trying to ascertain what they mean and so
2 forth.
3 I guess I'd start with back in March or
4 February when he had the initial workshop on the
5 assumption reports. I made the comment, I think,
6 it was difficult for stake holders to take these
7 reports and understand what you wanted from us.
8 And more importantly, I think I said I
9 find it hard to understand how policy makers can
10 utilize these reports to anticipate, and be
11 informed about, the decisions that you're going to
12 have to make in the next six months, 18 months, 24
13 months or whatever because of the way that, you
14 know, you need to, as policy makers, need to
15 anticipate things before they occur.
16 You need to know what the status quo is
17 today. You need to know, I think, what is going
18 to happen if nothing happens. And this report
19 imbeds in it a lot of assumptions throughout the
20 document. It was very difficult for stake holders
21 such as myself to decipher what it's meaning, or
22 what it pretends to mean.
23 Because it's kind of integrated kind of
24 the picture of where we are, a lot of assumptions.
25 And sometimes those assumptions aren't clearly

1 stated. And secondly, the piece that I think may
2 be missing in this is telling the market place,
3 policy makers, not only what the assumptions are,
4 but when on a timeline is a decision going to have
5 to be made to act in one or the other to solve a
6 potential problem that you see coming up.
7 So I'll get into some specifics a little
8 later. But my impression is that right now this
9 report, particularly if it's going to go to the
10 legislature, needs to be tailored in a way that
11 it's going to provide policy makers, particularly
12 with the Commissioners, with information from
13 which they can make informed decisions and predict
14 how to build, make decisions now that are going to
15 have an impact in three or four years.
16 Regarding the report itself, I'm pleased
17 to see that there is an emphasis, at least in my
18 reading about the importance of regulatory
19 certainty, and long-term contracts to stabilize
20 the electricity market, sending proper signals to
21 generation community, transmission community or
22 whatever about what needs to be built.
23 The language in this document speaks to
24 that, and I think it's very good that it takes a
25 strong position on that. One of the things that's

1 missing in this, and I'll speak a little later,
2 the timing of the assumptions that are imbedded in
3 this report.
4 It's not clear to me when I read it the
5 importance of your view of how the energy market,
6 and infrastructure, is going to develop, and the
7 connectedness with ISO having to do a market
8 redesign, or the ISO doing a transmission planning
9 study.
10 All of which are fairly speculative, and
11 pushed off time and time again. Meanwhile, you're
12 working with a real time dynamics pressured by the
13 Commissioners saying where are we today and what
14 are we supposed to do in the next six months or
15 next year.
16 But we've got these processes that have
17 fundamental implications for market design. And
18 they continually get pushed off. And it's not
19 clear to me how important that is to what you're
20 all doing in trying to put the information in the
21 picture to the Commissioners together.
22 And I think that is important for you to
23 manage through in this report, is the
24 interconnectedness between the factual situation
25 that you're trying to describe, the assumptions

1 that you're trying to describe, and the timing
2 that is out of your control.
3 Because that will help tell the
4 Commissioner, gee, we need to make a decision by
5 now. As an agency, take a position on this matter
6 in order to help these other agencies maybe move
7 forward. The other aspect of the report that I
8 noted is your emphasis on the importance of
9 competitive markets, which I think is good.
10 There was a reference to the importance
11 of the Spark Spread to new generation. And
12 there's language that speaks to the fact that I
13 think in the near term you think that Spark Spread
14 may be insufficient to send proper signals to
15 generation.
16 But then on the other hand, you note, I
17 think particularly in the context of the muni's of
18 the LSE's I think you described them as they will
19 move forward and build generation. And I'm
20 puzzled why they will move forward with generation
21 when Spark Spreads are narrow.
22 Why wouldn't they buy from the market
23 places as much as the IOU's. I think it's
24 probably because they are, from a planning
25 perspective, moving forward and entering into

1 long-term contracts in anticipation of building
2 huge planning reserve.
3 But that's not clearly said here. And I
4 think you could tease that out a little because
5 you're right on, but you've got two actors making
6 behavior decisions in the environment that are
7 different, seeing the same evidence.
8 And what is it that's going to fix that?
9 Which way do we want to go and how do we want to
10 send the IOU's in particular, if the muni's are
11 doing it properly, to get into the boat to be
12 doing the same kind of thing.
13 Another issue that I've noticed in my
14 review of this is, and it's more of a question, it
15 was not clear to me the firmness of the resources
16 that you have imbedded in your plan. And what I'm
17 talking about here are imports, in state
18 generation, DSM, and even the renewable piece.
19 How firm are your projections, for
20 example on imports? I think you've got a number
21 of about 8,000 imports, megawatts of imports in
22 there. How firm is that? Is that under contract
23 to anybody? And I don't know, I've heard comments
24 that you can't get to that information, but what
25 happens if the Pacific Northwest economic boom

1 reoccurs?
2 What's the risk or the probability that
3 those resources stay up in the northwest? What's
4 the risk that Denver's booms, Colorado Rocky
5 Mountain Region, and those imports go to the Rocky
6 Mountain Region rather than coming down here?
7 What's the likelihood of that?
8 I think some of those kinds of issues
9 are important for us as market participants to
10 evaluate the robustness of your assumptions in
11 your whole planning report. And the other similar
12 example is in state generation. There is a
13 significant amount of in state generation that
14 does not have a contract to an in state load-
15 serving entity right now.
16 A lot of that is being, from my
17 understanding, is being operated pretty much
18 within the ISO market structure, which has some
19 RMR requirements, but also has some other
20 structures on what those generators can do.
21 What's the likelihood that that
22 generation will escape from that either by not
23 finding it economically feasible to run and
24 shutting down, or selling their generation to an
25 out of state entity?

1 Similar with DSM, I remember years ago
2 back in the planning days when we had the concept
3 of uncommitted DSM, and committed DSM. You kind
4 of remember that that kind of drove some of the
5 planning assumptions. How firm are we on the
6 assumption of DSM and its robustness continuing
7 over time?
8 How firm are we on the renewable thing?
9 I'm going to speak in a little greater detail on
10 the renewable issue because you've got some
11 assumptions in there that I think the discussion
12 just touched on about transmission, maybe way off
13 base.
14 Because you've got an assumption of
15 1,000 megawatts of wind, where's it going to come
16 from if the transmission in Tehachapi isn't built?
17 And as we've heard, there may be a huge delay in
18 that, if not nothing built because it's not,
19 quote, economic from the ISO's perspective or
20 someplace else.
21 Where are the 1,000 megawatts going to
22 come from? The other issue that I had, and then
23 on the table you spoke for your one and two, and
24 one in ten projections on operating reserves. And
25 it wasn't clear to me whether that's a WECC

1 operating standard, operating reserve standard,
2 the seven percent number, the definition of
3 operating reserves.
4 Or was that encapsulating planning
5 reserves as well? It looked to me to be an
6 operating plus planning reserve issue. The WECC's
7 have some certain standards on operating reserves.
8 You've got to maintain seven percent, and they've
9 got have these certain kind of characteristics and
10 readiness and so forth.
11 The planning reserve is a little
12 different. And that usually gets to the issue of
13 resource adequacy in that planning structure.
14 They're separate in some respects. And I think
15 you need to tease out whether you've got them
16 characterized properly or not.
17 If they're operating reserves, that's
18 fine. You can probably make a footnote that
19 that's what that is, and it's consistent with the
20 WECC standard. If there's planning reserves in
21 there and they're being driven by assumptions on
22 resource adequacy, we probably need to know that.
23 And then finally in the report itself, I
24 know the report speaks to the fact that things
25 look fairly good between now and I think 2006,

1 2007, which is good. That's good news for
2 California. I am concerned though that we're
3 within about ten days of the ISO having issued a
4 stage I alert in the month of May about the status
5 of the California energy structure.
6 So in my mind, it's how close are we to
7 a very fragile situation if temperatures drive up,
8 you know. This year we're a very robust hydro,
9 but what about next year? I mean I was probably
10 amazed as a number of other market participants
11 because right after you had released your report
12 basically saying things look pretty good as a
13 staff draft, you know, the ISO comes out with,
14 boy, we've got problems here. We're in a stage I.
15 And I thought we were more robust than
16 that. So I think that is something that we could
17 probably focus on. On transmission related
18 issues, I've just got a general comment, and I've
19 alluded to one, is basically what is the impact of
20 the transmission assumptions on the electricity
21 report?
22 And, you know, again, going back to the
23 assumption that there's going to be a 1,000
24 megawatts of wind in California serving the RPS,
25 where's that coming from? And how is important is

1 the transmission assumption on Tehachapi and other
2 places to feed them?
3 There is an interconnectedness between
4 the transmission and generation. We all recognize
5 that. But it's not clear to me what the
6 interconnectedness is in your modeling. And that
7 happens throughout the document. I mean all the
8 things you're doing is so complex.
9 And you've got imbedded a series of
10 assumptions, but if one assumption does not come
11 true, is there an expediential effect on another
12 assumption that we're not modeling or thinking of
13 right now? They all seem rather discreet to me at
14 this point.
15 And I think they are very, very much
16 connected.
17 MR. ALVARADO: Steve, how about maybe if
18 I could sort of just assert myself here to add a
19 little perspective. As we indicated earlier
20 today, we are holding a whole series of different
21 workshops. There are other subject others, staff
22 reports. We are trying to examine a lot of these
23 different areas, you know.
24 You're taking a pretty broad brush
25 approach and question to our process. The other

1 day we had a workshop on efficiency issues. We
2 will be having another workshop that's going to
3 cover renewable technologies.
4 For perspective, what we're doing here,
5 at least on this report, was not coming up with a
6 preferred identified resource, long-term resource
7 plan, as we've done a number of years ago, which
8 involves really getting out a lot of the
9 assumptions we would want to include, engage in a
10 screening analysis to evaluate the benefits of
11 each of the resources.
12 The study that we're talking about today
13 is really just trying to first identify what kind
14 of uncertainties we could probably confront in the
15 future. Some of these assumptions we've taken
16 regarding renewables in DSM is sort of a figure
17 magnitude to see if so much DSM and renewables
18 were brought into the California system, how that
19 might really effect the need for other new
20 generation.
21 And further down the line we'd like to
22 examine what would be the implications to the gas
23 system.
24 MR. KELLY: I understand how complex
25 this is. So don't get me wrong, I mean this a

1 very difficult thing. And there are statewide
2 implications and regional implications. And
3 there's no better agency to deal with even the
4 regional implications of this than this
5 Commission.
6 You have the expertise, and the people,
7 and the will, and the understanding of how to do
8 this. It's very complicated. But from, you know,
9 a stake holder's perspective, trying to help you
10 in these workshops, grapple with this -- I mean
11 when I first got the report I went through it
12 fairly quickly and then shuffled it off to some
13 people that I respect a lot and asked them to give
14 me some feedback on it.
15 And they were -- the questions, well, we
16 don't have a lot to say on it. So I gave it
17 somebody else and the answer came back basically
18 the same. We really don't have a lot to say on
19 this. It was hard for them to grapple with this.
20 And I have a feeling it has to do with, you know,
21 how it's structured.
22 You know, people ask, what do you want
23 us to say? What do you want us to -- how are we
24 supposed to deal with these assumptions? It's
25 hard for us to pull out all of the assumptions and

1 so forth, which kind of gets to my issue that I've
2 been tinkering with was, you know, and this is
3 just observations to help the product, the work
4 product.
5 But I think there are things you could
6 do to this report that would make it better for
7 market participants for example, and hopefully for
8 policy makers who are really going to be
9 struggling with these issues. I think, you know,
10 you really a chapter in something like this that
11 says, you know, here is where we are today.
12 And if we don't -- and, you know, it's
13 an infrastructural report. We don't invest in
14 anything. This is what's going to happen and when
15 it's going to happen we think based on load
16 assumptions, you know. Just don't presume
17 anything about infrastructure.
18 And tell policy makers, if we don't do
19 anything this is what we think is going to happen
20 and when. That's going to send a signal to policy
21 makers and to people like me about, gee, we need
22 to get off and we need to focus on that issue. We
23 need to start resolving the infrastructure
24 problems associated with what you're seeing as
25 looming down the road, either, you know, two

1 months, five years, ten years down the road.
2 Secondly, I think it would be helpful to
3 include in a report like this all of your
4 assumptions, just lay them out by DSM, by
5 generation, by transmission or what, so that
6 people can see them all in one spot and come to
7 some sense about, gee, do all those assumptions
8 make sense?
9 And when you integrate them and, you
10 know, what's the interconnectedness between them?
11 And it will make it easier for us to evaluate the
12 connectedness between the assumptions that you've
13 made, and maybe get at is there a problem in the
14 assumption, and do a fail safe kind of review
15 about these are reasonable and we don't see any
16 problem there.
17 Third, I think it would be helpful in a
18 report like this to include a time frame that
19 says, you know, here's what we see. Here's a
20 schedule of when the ISO was supposed to complete
21 its market redesign. Here's a schedule when the
22 PUC is supposed to do its transmission based on
23 what we know today.
24 Is that adequate for what we're seeing
25 from an infrastructure need prospective? Where

1 are the disconnects on that? What's the
2 likelihood they're going to be delayed further?
3 As Commissioner Boyd pointed out, all these
4 proceedings that are on a schedule that you see
5 today, invariably they get delayed.
6 I mean we're working on issues at
7 Tehachapi or whatever that have a high probability
8 of being delayed. And what's the implication of
9 that? And from the state perspective then we all
10 can assess how important it is to raise issues at
11 FERC, or at the PUC, or here at the legislature to
12 solve these problems.
13 So and in that process you almost for
14 policy makers certainly are creating kind of
15 warning triggers on the time frame. We think of
16 staff or as a Commission that if you don't make a
17 decision by this point in time we are in jeopardy
18 of having a problem.
19 We are raising the risk of a problem.
20 And that will signal the people more effectively
21 that a decision has to come down and win. I think
22 that will be helpful for the planning process.
23 Those are all my 40,000 foot observations.
24 PRESIDING MEMBER BOYD: I saw you turn
25 your page back. Were you really done? Don't let

1 Al's comment chill you because this is the
2 opportunity --
3 MR. KELLY: No, I think I'm pretty done.
4 Al's comment didn't chill me.
5 PRESIDING MEMBER BOYD: We don't hear
6 enough from the public in these, so this is your
7 opportunity to let it all out.
8 MR. KELLY: I think one of the reasons
9 that you don't hear more from the public, I don't
10 think it's because their advocates are so great.
11 I've gotten stabbed in the back a million times.
12 I know that's not true. I think it's because
13 people have a hard -- one, everybody is very busy,
14 you know.
15 Within the last week and a half I must
16 have gotten 400 page reports from this Commission,
17 and three proposed decisions from the PUC of equal
18 length that everybody is struggling with. So it's
19 a time where everybody is very busy.
20 But secondly, I think for this
21 particular report, like I say, I had two separate
22 consultants take a look at this and say, all
23 right, what do you want me to say? What should I
24 say when I get up in front the (indiscernible).
25 And they really struggled with how to

1 guide me to make a presentation to you. And they
2 didn't do a very good job because you can see I've
3 (indiscernible) this morning. But anyway, this is
4 a very difficult subject. And it was hard for the
5 stake holders to I think get their hands around
6 it.
7 CHAIRMAN KEESE: Let me interject an
8 observation here because you are voicing a concern
9 that impacts us greatly when we were talking with
10 staff about scoping this hearing, this whole
11 process, PR process. And had we, as a committee,
12 chosen to decide where we're going with this, and
13 then had staff back us up, it would have been much
14 easier for this process, because we would have
15 said this is the road we're going.
16 Give us the report that gets us there.
17 We chose not to take that course. We gave staff a
18 really difficult burden. We said we're not going
19 to tell you where we're going. We want you to
20 look at everything, baseline, projections. Bring
21 it to us and then we will decide where we're
22 going.
23 Now, I absolutely recognize that creates
24 a problem for the public. But you have made some
25 very strong points about this baseline that we

1 have that will be helpful to us. The next step
2 will be we'll tell you from this where we're
3 going. And that's the point in which I think your
4 consultants will say you're nuts, you know, about
5 Tehachapi wind or whatever it is.
6 Commissioner Boyd and I, I will tell
7 you, have struggled with how to do this. But we
8 don't see any other way to build an open process
9 on the first time we're doing a report that's
10 going to carry on for years, and years and years.
11 We really can't make the assumptions
12 holding up. So to the broadest as possible we
13 want staff to lay everything out for us. And
14 that's why I encouraged at the front end any
15 recommendation you have will be considered.
16 If you can glean anything out of this,
17 or if we can get other members of the audience to
18 hit us a few times. Tell us what they think we
19 should be doing. I appreciate what you've told
20 us.
21 MR. KELLY: Well, I think it's very
22 important that staff take that first step and just
23 lay it all out, you're right. The piece that I
24 don't see laid out right now is, you know, if we
25 don't do anything where are we?

1 CHAIRMAN KEESE: I think that's a good
2 point.
3 MR. KELLY: Because I think that first
4 starting point is critical here. Every time you
5 do one of these, this is where we are and, you
6 know, we're fine or we're not fine based on that.
7 And if we're not fine, this is what we've got to
8 do. And then you start getting into the
9 assumptions about, you know, is this plant going
10 to come on in two years?
11 What's the likelihood of that going to
12 happen in four years, or not?
13 CHAIRMAN KEESE: You know, you mentioned
14 the disconnect between IOU and the muni actions on
15 development. I think that's what we will glean
16 out here when we say integrated policy report.
17 We've got to figure out how to bring those aspects
18 together. I'll tell you, at the end of the day
19 the reasons the muni's are going forward is
20 because they have the resources to build, which
21 the others don't have.
22 Now, that skips your question of
23 judgement about the future market. And I think
24 you're right, the munis and others have been
25 forced to take the risk themselves without a PUC

1 guidance. And they have chosen generally to not
2 go on the spot market for everything, to hedge one
3 way or another.
4 And I think building generation is a
5 very realistic hedge if you have the assets. And
6 you can probably see that nobody else has funds.
7 So look at a two or three year time frame to build
8 power plants by the year 2006, 2007, we will be
9 ahead of the curve. We will have built the plants
10 and nobody else is.
11 MR. KELLY: But, you know, there's some
12 language in here about the balance sheet of
13 particular generation community. And in the
14 procurements that have occurred over the last 12
15 months, 18 months, the few that have occurred,
16 whenever they have occurred there's been -- the
17 utilities, from my understanding, have been
18 inundated with offers.
19 There is, particularly with the interim
20 procurements that occur in the last quarter of
21 2002, not only did the renewable community, you
22 know, swamp the resource need that was out there
23 as defined by the utilities. But the thermal
24 community responded as well.
25 The difference was in that context there

1 was contract, and there was a commitment forward
2 with the contract and get it in place. And even
3 there were short-term contracts, you didn't see a
4 lot of green fill development into that.
5 I think it was a signal that the real
6 difference between the munis and the IOU's is that
7 the muni's can bill it on their own balance sheet,
8 or they'll do a contract. And that's not
9 happening right now. I know the PUC is moving
10 aggressively on that. And we're working with them
11 on that.
12 And hopefully by the end of the year
13 that will be all resolved. But while there are a
14 limited number of independent power producers that
15 have balance sheet problems, there is a number of
16 companies that are moving forward. And their
17 position to respond to these RFP's if and when
18 they're let out.
19 So and my answer to that is, you know,
20 regulatory certainty and, you know, a contract,
21 which the staff have appropriately pointed out,
22 are fundamental to making this work.
23 CHAIRMAN KEESE: And that's the
24 integration --
25 MR. KELLY: Yeah.

1 CHAIRMAN KEESE: -- we're going to have
2 to take here before this report comes out.
3 MS. GRIFFIN: Steve, I wanted to respond
4 to one of your factual questions in your long --
5 MR. KELLY: Sure.
6 MS. GRIFFIN: Because it was addressed
7 in a workshop last week. And that was on how
8 confident are we in the DSM numbers. And we had a
9 DSM workshop. And we're grilling the experts on
10 that. They gave us a couple of key facts, one was
11 that historically projections have been met plus
12 or minus ten percent.
13 So in terms of, you know, when you go
14 back and you look at we're going to X from program
15 savings, and did they get it or not. Basically,
16 you know, within a reasonable band they did. So
17 we have one fact point that says in the past, when
18 people have been estimating programs, they've been
19 pretty good at it.
20 The second thing we said, okay, well,
21 that's the past. Here's now. Are these -- do we
22 have more or less potential because of all the
23 saturations we're got so far, or new technologies,
24 or harder to reach audiences. Because I don't
25 know if you have seen the DSM potential studies

are out there.

But everybody is using the same data. And it says that we could quadruple the amount of money that we put into PGC funds and still be investing in cost effective on a total resource cost basis. And, okay, guys, how confident are you in those numbers?

And what they've said was, we really are confident on the measure by measure number. But there's a big gap between measure by measure added up into programs you can actually deliver to consumers. And so they were not embracing (indiscernible) right at the moment.

They were saying, yes, we believe that the PGC investment, just at the amount of money that we have now, they felt very confident about the quality of their ability to deliver that. And that they felt pretty darn good. But maybe with a ten or 20 percent discount rate in a doubling of that amount of money.

But we're not at all confident or comfortable at going much beyond that. And we're saying, but that's not a decision we need to make today. The decision we need to make today is to restart and reinvigorate, and fix these DSM

1 programs, and get it up to a certain level.
2 And then in two to three years we'll
3 come back and look at the next increment. They
4 certainly recognize that there's a lot of
5 rebuilding of that DSM community that has to
6 happen in the administration, get that
7 straightened out.
8 That was why, I think, we were seeing a
9 certain emphasis on let's get going in this way,
10 but don't believe that we're committing now for
11 all time.
12 MR. KELLY: Well, I mean it sounds like
13 you're asking us to have the right questions of
14 your consultants, whoever you're asking those
15 questions of, you know. If you take that
16 information when it gets into this report, you
17 know, that it sounds, you know, committed.
18 You know, you're pretty confident that
19 that level is going to be there. And that's
20 important to know for me who does not attend the
21 DSM meetings for example. But when I read a
22 report it's helpful to know that, how firm that
23 is.
24 PRESIDING MEMBER BOYD: Steve, you
25 mentioned the stage I we had this year, which was

1 a wake up call for a lot of people. I was
2 particularly impacted because the previous day I
3 participated in the big press conference at the
4 ISO to appeal to everybody it's the start of the
5 season, you know.
6 We have to think of conservation,
7 etcetera, etcetera. And the very next day we get
8 slapped with that. I said, well, great response
9 by the public. But in really looking into it, it
10 was, okay, May they tell me is the toughest month
11 to predict mother nature, the weather.
12 And, you know, they blew it on the
13 temperature. And there was, you know, probably
14 15,000 megawatts of energy available in terms of
15 economic off line, etcetera, etcetera. So that
16 gave some feeling of security that, well, this
17 isn't a precursor to 2001 all over again.
18 But I agree with you, I mean you've got
19 to check all these signals, and there aren't
20 guarantees that if we have a western heat storm
21 again or something, that California megawatts are
22 running across the board or somewhere else.
23 That is a dilemma. But we feel pretty
24 -- you know, we feel very good about this year,
25 and the next couple of years. It's the

uncertainty of the future and a lot of the points that were made about economic recoveries in other places other than California impacting the whole system.

But the glacial alacrity which with this system responds to fixing our future is of a concern to a lot of folks. I think the concern is reflected in the energy action plan, and desires three agencies to try to grab the bull by the horns, at least to some degree, and more aggressively move out in this world, which, you know, accelerates any given day in terms of how you react to it.

But your points are good points. And to your credit, I took more notes than I have in a long time. And I appreciate your input because this is a workshop, and it's supposed to be fairly informal. And it really is an opportunity for people, albeit polite, to challenge people's assumptions if they can dice them out.

I heard that message. And we welcome, and I welcome for the staff because I'm sure they welcome too, inputs. Because, you know, we want to be more right than wrong when we finish this thing. And the only way we're going to know that

1 if you test and retest things.
2 So tell your consultants to sharpen
3 their pencils and keep digging.
4 MR. KELLY: I will.
5 MR. ALVARADO: Maybe even out of that,
6 Steve, heads up to you and your consultants, we do
7 plan on releasing a draft, electricity natural gas
8 report, for the end of July where we're going to
9 try to knit together a lot of the assumptions and
10 some of the findings of our studies.
11 MR. KELLY: Okay. That will be great.
12 I look forward to it. Thank you.
13 PRESIDING MEMBER BOYD: Al, I'm going to
14 suggest that you ask for a show of hands of how
15 many people are going to come up and testify in
16 this now open public testimony period that is
17 scheduled to run after the lunch break all the way
18 to the end of the day.
19 If we don't have a lot of folks who have
20 something to say, we must as well press on. If
21 we're going to have a lot of people then we can
22 feed them all so to speak.
23 MR. ALVARADO: Okay. Please. Well, it
24 looks like we just have two speakers. So I
25 suggest we maybe carry on.

1 PRESIDING MEMBER BOYD: Keep going.
2 MR. ARTHUR: My name is Dave Arthur.
3 I'm with the City of Redding. I'm a resource
4 planner there. Which just to give you a
5 background, involves long-term arrangements for
6 gas, fuel for our power plants, long-term power
7 contracts, relationships with the California ISO
8 and FERC matters.
9 So it covers a broad spectrum, and so
10 while I probably don't know a great deal about
11 anything, I get to see an overview of a lot of
12 things. First of all, I would like to say I think
13 the reports, and actually the gas report that
14 we'll talk about tomorrow, are both extremely well
15 done.
16 They're very helpful to me in the sense
17 that in one place you can start to see a lot of
18 information presented. And the upside of that is
19 that you can begin to see whether the pieces seem
20 to fit together or not in a way that is
21 impossible, if that isn't correlated in a coherent
22 understandable manner.
23 The downside I guess is that as you
24 start to see all of the pieces come out you can
25 begin to start to ask questions as to whether the

1 different directions we're going seem to make
2 sense, or whether because most of us live in what
3 I would characterize as a more cartesian world we
4 each have our own little part.
5 We optimize there, but we don't
6 necessarily see the linkage to other sorts of
7 things. And so some of my comments are going to
8 be directed to what I see at least some potential
9 issues that come out in getting to see all of this
10 information in a single place.
11 It seems to me that one of the things
12 that we've learned, and in fact in the different
13 arenas that we spend enormous time sharing
14 differences of opinion around, has to do with the
15 fact that generation and transmission, and load
16 centers are intricately linked.
17 And even though we have, as a state,
18 chosen to treat them as separate for reasons that
19 those of us in the municipal world still do not
20 understand, we accept the fact that that is the
21 policy of the state.
22 And so I want to make a couple
23 observations as it relates to the fact that they
24 are linked even though we tend to formulate policy
25 as if they were not.

1 It seems to me that one of the things
2 that is coming out of the work that the ISO has
3 done, and the work that's being presented here, is
4 that location is more important than ever. That
5 is to say that where generation is actually
6 located can be almost as important as how much of
7 it that you have.
8 And what we saw today is that we seem to
9 have a sufficient quantity. It's not entirely
10 clear we have it in the right places. And
11 correlated to that is we start to talk about
12 transmission enhancements. And it seems to me
13 that one of the distinctions that was drawn was
14 between something that was called a reliability
15 improvement, or an upgrade, and an economic
16 improvement or upgrade.
17 And I have to confess, the first time I
18 heard the distinction was probably two or three
19 years ago. And it was at the CAL ISO, and it was
20 when they were wrestling with some of these same
21 questions. And Kellan made some what I can only
22 characterize as brilliant presentations in which
23 he took extraordinarily complex matters and
24 distilled it down to those of us without a
25 transmission background to being to understand

1 what he was talking about.
2 But at the end of the day I think it
3 became clearer and clearer that drawing a
4 distinction between economic and reliable
5 transmission may have resulted in some serious
6 misunderstandings. And may have led us in some
7 very faulty directions as it related to how much
8 transmission we need.
9 Because at the end of the day it may be
10 much more important to ask the question is state
11 policy going to be focused on a return to a more
12 cost based type arrangements, or are we going to
13 actually try and move forward with a market based
14 approach?
15 And I think that even the market
16 surveillance committee has acknowledged, certainly
17 with reluctance, but they have acknowledged that
18 you probably need more infrastructure, and a
19 different kind of infrastructure if you want to
20 facilitate and enhance competitiveness then what
21 you need if you want to remain cost based, sort of
22 like in the old world.
23 And so it seems to me a more productive,
24 or at least in addition, could be say if we move
25 forward with an effort to have workable markets,

1 where do we need additional transmission in order
2 to have sufficient infrastructure so that those
3 markets have a reasonable prospect of working?
4 And I think that will lead to some very
5 different conclusions. For example, and I'm
6 working from my recollection here, I may slightly
7 misspeak and hopefully Robert will correct me if I
8 do. But my recollection is in the most recent
9 MDO2 draft it's pointed out that there is
10 confidence only that there's really strong
11 workable competition most of the time between SP15
12 and NP15.
13 And that in many other areas significant
14 quantities of what we lovingly call on the ISO
15 world mitigation will be required in order to
16 provide adequate price protection for the
17 consumers. Well, that suggests that we need quite
18 a bit of transmission, if it is to be the state
19 policy to move forward with more competitive
20 markets.
21 So I throw that out as you think about
22 an integrated plan, an integrated plan for which
23 type of environment. A second is that we've
24 talked about, and it was interesting to see, that
25 if we are successful in more a renewable program

1 that we wouldn't develop nearly as much gas fire
2 generation.
3 Now, without endorsing gas fire
4 generation or condemning it, I will point out that
5 it's very flexible as to where you can locate it.
6 And if renewables on the other hand are much less
7 flexible as where you can locate them, they seem
8 to have preferences.
9 So one seems to get located where wind
10 blows, and the sun seems to get located, at least
11 in most instances, where the sun shines a lot.
12 And so if we move toward more renewables that will
13 probably turn out to have a profound impact on
14 where generation is built, which will turn around
15 and have a significant implication where the
16 amount, and type and quantity of transmission that
17 we have or need.
18 And for example, in the NDO2 implicit in
19 that is a desire to put out price signals as to
20 where generation is needed. Now, the presumption
21 there is that generation is flexible with respect
22 to where it's located. If it turns out that our
23 policy is to have a type of generation that isn't
24 very flexible in terms of its location, then to
25 have adopted a pricing policy for transmission

1 allocation that's predicated on flexible
2 generation location, creates some pretty serious
3 policy gaps potentially.
4 And we could see that we have unintended
5 and less pleasant outcomes surrounding that type
6 of thing. And then the last point I want to make,
7 having to do with these inter-relationships, it
8 was really interesting, I've been two national gas
9 conferences in the last three weeks, four weeks,
10 and in each of those there is a profound
11 confidence that we will heavily on L&G.
12 And there was a profound pessimism as it
13 related to the supply and demand characteristics
14 if we don't get L&G. It is the view at least of
15 those in the gas industry that at least one,
16 possibly two, but at least one major facility will
17 probably be built in Baja, California.
18 And that will have profound implications
19 for the sighting of additional generation. And it
20 will, therefore, have profound implications on the
21 need for the associated transmission. And it may
22 or may not have profound implications on the type
23 of generation we've actually come to rely upon in
24 the future as well.
25 And so I'm sure that tomorrow we'll talk

1 much more about this, but, again, it just simply
2 brings out the fact that policy decisions being
3 made in one arena will turn out to have a very
4 significant impact on the policy decisions we need
5 to make in other arenas.
6 And to close, three or four times this
7 morning I've heard reference to we might have a
8 little excess capacity. That seems to me to
9 actually be one area where I think this body could
10 be extremely helpful to the people of California.
11 And that is to explicitly address the question is
12 having a little too much a much greater or a much
13 smaller error than having too little.
14 And it seems to me that that's an
15 extraordinarily important question because all of
16 us that have ever had to forecast know we will be
17 wrong. But we can bias the direction so that when
18 we're wrong it either probably results in too
19 little or too much.
20 And we probably ought to error, at least
21 based on what our judgment is, as to where the
22 more profound error is. I think I should comment
23 briefly simply on the discussion that went on with
24 the previous speaker as to why municipals seem to
25 be following behaviors that are different than the

1 IOU's.

2 And I actually use to work for an IOU.

3 So I actually know a little bit about their

4 decision process as well. But I don't think that

5 the munis are doing anything particularly unusual.

6 We start with a very simple premise. Our goal is

7 to minimize the long-term cost for our consumers,

8 to do so without imprudent risks, and to ensure

9 reasonable reliability.

10 We do differ from some that we think we

11 have to start with our customer's preferences.

12 And in that respect, they have told us that they

13 want to have power pretty much on demand without

14 enormous variances in price by the time in which

15 they use it.

16 So we go out and we attempt to build a

17 system that is tailored to respond to that set of

18 priorities. We feel that we should have a

19 diversified portfolio. So for example, we do in

20 fact buy long-term contracts from the market. For

21 the most part we're glad to do so.

22 We've discovered is that it's hard to

23 retain one of those. The City of Redding had one

24 contract turned over at least once with some

25 prospect of it turning over again is the vendors

1 seem to keep withdrawing from the market. On the
2 gas side, we've attempted to, again, reduce
3 volatility.
4 We've become, for example, a shipper all
5 the way to Peco to ensure that we have a physical
6 supply of gas that will always be available around
7 a plant. We've done a number of forward market
8 purchases in the gas markets to try and minimize
9 the volatility, because volatility is something
10 that gives problems to our customers.
11 They don't want the -- certainly other
12 types of customers may very well accept that
13 volatility, and that's an individual customer
14 choice. But we have found is that we are just
15 doing the basics. Now, what I've tried to explain
16 here, that doesn't get us into really being
17 vertically integrated or not.
18 It simply says we've got an obligation
19 to customers. We've gone out and tried in the
20 forward markets to create a diverse supply and
21 hedge the volitilities where we think it's
22 appropriate. And I think too often we surround
23 ourselves with ideological emotions over some of
24 these terms rather than simply getting back to the
25 basic, which is we should all be here to try and

1 keep the prices down, the reliability up, and we
2 should use the various techniques available to us,
3 which can include competitive markets.
4 They can include spot markets. It can
5 include building. There isn't one that's right
6 and one that's wrong. In fact, what we've found
7 is that there's a place for all of them that were
8 better off if we had all of them rather than if we
9 spend too much time arguing that there should only
10 be one, or there should only be the other.
11 That seems to limit choice. And the
12 goal is to expand choice. And when we've expanded
13 choice we've always come out with a better
14 outcome. Thank you.
15 PRESIDING MEMBER BOYD: Thank you.
16 CHAIRMAN KEESE: Thank you.
17 MS. BACHRACH: Good afternoon. My name
18 is Devra Bachrach. I'm here on behalf of the
19 Natural Resources Defense Council. I promise I'll
20 keep it short because I know everyone wants to get
21 some lunch. Thank you for the opportunity to
22 provide comments today on the staff report.
23 And I'd like to first start by
24 commending the staff for the considerable effort
25 that's gone into creating this draft report. And

1 I'd like to commend the Commission for all of the
2 effort going into the entire Integrated Energy
3 Policy Report process.
4 My comments today will focus on how the
5 staff report incorporates energy efficiency into
6 the demand forecast in the assumptions related to
7 energy efficiency. Overall, the staff reports
8 assumptions related to energy efficiency have
9 improved considerably since the drafts that were
10 issued in February.
11 So I'll highlight some of these
12 improvements, and I also have several suggestions
13 on how to revise the DSM scenarios to more
14 realistically represent the current state of
15 California's electricity industry. So let me
16 begin by commending the Commission for the
17 improvements in the staff reports since the
18 February draft.
19 And I'll highlight two important
20 improvements, first the staff report now
21 incorporates energy efficiency into the demand
22 forecast, where as the initial forecast did not.
23 This is obviously an important improvement.
24 And second, the staff report
25 incorporates the effect of energy efficiency in

1 the demand forecast rather than placing it on with
2 the supply side of the picture. This is important
3 because the demand forecast are used as inputs to
4 many other parts of the IEPR report.
5 And so excluding the energy efficiency
6 impacts from the demand forecast could askew the
7 results of other parts of the IEPR, such as the
8 transmission infrastructure plan, or the natural
9 gas infrastructure plan. So the forecast has
10 improved.
11 We think that there's some additional
12 room for improvements. First, to make the
13 baseline demand forecast as close to reality as
14 possible, it should include both the minimum level
15 of PGC investments required by law, and the
16 utilities plans for additional investments in
17 energy efficiency.
18 The best information that we have right
19 now about how much California will invest in
20 energy efficiency going forward is contained in
21 the long-term procurement plans that the utilities
22 filed at the Public Utilities Commission on April
23 15th.
24 This information should be included in
25 the CEC baseline demand forecast since it's the

1 best state of our knowledge right now. The
2 procurement plans that the utilities filed show
3 that they plan to increase investments in energy
4 efficiency by nearly two-thirds, thereby nearly
5 doubling he energy savings relative to just having
6 the PGC fund the programs.
7 So if the CEC were to omit the utilities
8 plan from the demand forecast, it would almost
9 guarantee from the start that the baseline
10 forecast would be incorrect going forward. We
11 also suggest that Commission revise the DSM
12 scenario so that they expand the range from at the
13 low end, the minimal level of investments and
14 energy efficiency required by law, which is the
15 PGC fund investments.
16 And that the high end acquiring all cost
17 effective energy efficiency, which is California
18 policy. Now, you pointed out that one of the
19 goals of this report is to identify key
20 uncertainties.
21 And I think that the main uncertain
22 variable when it comes to energy efficiency
23 investments is how much the utilities, or how the
24 utilities will respond to the PUC's directive for
25 them to consider all investment -- all cost

1 effective energy efficiency investments.
2 So for the Commission's scenarios it
3 would be most logical to this variable as the
4 uncertain variable, varying it from, you know, n o
5 additional procurement investments, meaning just
6 the energy efficiency investments requirement by
7 law at the low end, to procuring all of the cost
8 effective resources at the high end.
9 This proposal that we're making to you
10 would alleviate some of the problems that we see
11 with the current scenarios that are included in
12 the report. Let me start just by reminding you
13 what the current scenarios are. At the low end,
14 the report assumes absolutely no investment in
15 energy efficiency going forward. That the law
16 would be changed so that there would not be a PGC
17 requirement.
18 For the baseline, the report assumes
19 that only the PGC fund investments are made, and
20 at the high end the report assumes that the PGC
21 fund would double the investments made in energy
22 efficiency.
23 And these scenarios are not very
24 realistic. The low DSM scenario in which
25 absolutely no investments in energy efficiency are

1 made going forward is highly unlikely, first
2 because of the PGC funds are required by law.
3 It would require a law change. It's
4 also an unnecessary scenario I think because this
5 scenario could be understood just by simply
6 identifying clearly how much of the baseline
7 scenario is assumed to come from energy
8 efficiency, but could then be inferred from.
9 The high DSM scenario as its currently
10 included in the staff report is right now only
11 slightly more aggressive than what the utilities
12 themselves are planning to do. And, therefore,
13 it's probably closer to reality right now than the
14 staff reports current baseline forecast.
15 So to make the full range of the
16 scenarios more realistic we think that on the low
17 end, for the low DSM scenario, it should include
18 only the PGC fund investments that are required by
19 law for the baseline to include both the
20 investments required by law, and what the
21 utilities plan to do through their procurement
22 panning process.
23 And at the high end to include
24 investment and all cost effective energy
25 efficiency consistent with California policy. And

1 I realize that staff might have more work to do to
2 try to define what would constitute all cost
3 effective energy efficiency.
4 But I think that would be a better range
5 for the Commission to look at to vary between
6 these ends of the spectrum. Finally, I also
7 wanted to urge the Commission to explicitly denote
8 in the next version of this report what
9 assumptions are being made about the savings that
10 will come from the Energy Commission's energy
11 efficiency standards.
12 As you know these standards result in
13 very significant energy savings. So the forecast
14 should delineate the amount of savings that are
15 soon to come from the past both building and
16 appliance standards, and the anticipated effect of
17 the 2005 update of the building standards that's
18 currently underway, and the recently initiated
19 proceeding to update the appliance standards.
20 So that concludes my comments. Thanks
21 again for your time, and for considering NRDC's
22 comments.
23 CHAIRMAN KEESE: Thank you.
24 PRESIDING MEMBER BOYD: Thank you.
25 MR. ALVARADO: Do we have any other

1 comments or questions while we have the
2 opportunity of our staff up here? It looks like -
3 - unless, David or Judy, do you have anything else
4 to sort of clarify any of the assumptions you
5 used, BLT hold the mayo?
6 The only other thing I'd like to add, I
7 probably should have said this earlier, is we're
8 still open to receiving any comments based on
9 either the discussion we had today or if anyone
10 else now has an opportunity to read the reports
11 and can see it with a different light.
12 If you do have any comments please file
13 them by June 20th, the sooner the better. Because
14 we are at this point starting to write the
15 electricity and natural gas report, which I
16 indicated we do plan on releasing towards late
17 July.
18 With that being said, I just want to
19 remind the folks that tomorrow we will be
20 discussing the staff's natural gas market outlook
21 report. Actually, market assessment report, which
22 sort of carries forward some of the findings that
23 we have, the electricity scenario analysis.
24 But tomorrow we'll discuss
25 (indiscernible) implications to the natural gas

1 system. With that being said, I propose we
2 adjourn this workshop.
3 PRESIDING MEMBER BOYD: Thanks,
4 everybody, for your comments, I appreciate it.
5 (Thereupon, at 12:35 p.m., the Committee
6 Conference was adjourned.)
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CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 19th day of June, 2003.

ALAN MEADE