COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	)
Preparation of the 2008 Integrated Energy Policy Report Update and the 2009 Integrated Energy Policy Report	) Docket No. 08-IEP-1
	)
Long-Term Electricity Procurement Issues	)

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10:04 A.M.

ORIGINAL

Reported by:
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COMMISSIONERS PRESENT

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Karen Douglas

ADVISORS PRESENT

Laurie tenHope

Tim Tutt

Panama Bartholomy

STAFF PRESENT

Suzanne Korosec

David Vidaver

Mike Ringer

ALSO PRESENT

Simon E. Baker
California Public Utilities Commission

William B. Marcus
JBS Energy, Inc.
The Utility Reform Network

Fong Wan
Pacific Gas and Electric Company

Carl H. Silsbee
Southern California Edison Company

Jane Turnbull
League of Women Voters

Cliff Chen
Union of Concerned Scientists

I N D E X

P R O C E E D I N G S

10:04 a.m.

MS. KOROSEC: This is the August 18th Integrated Energy Policy Report workshop on procurement issues. I'm Suzanne Korosec; I'm leading the IEPR effort this cycle.

We'll just go over a few quick housekeeping items before we move on to the staff presentations.

For those of you who haven't been here before, the restrooms are out the double doors and to your left. There's a snack room on the second floor at the top of the stairs under the white awning.

And if there's an emergency and we need to evacuate the building, please follow the staff as we scurry out the door to the park across the street and wait for the all-clear signal.

I'll turn it over now to the Commissioners for opening comments.

PRESIDING MEMBER BYRON: Thank you, Ms. Korosec. Good morning. I'm Commissioner Byron; and I'm the Presiding Member of the Integrated Energy Policy Report. Welcome to our Committee workshop on the topic of electricity procurement.

With me is my Associate Member on the IEPR Committee, Chairman Pfannenstiel. And I believe joining us at the dais will be her Advisor, Tim Tutt. And my Advisor all the way to my right is Laurie ten Hope. I think Commissioner Douglas will be joining us at some time during the morning.

I really don't have any opening remarks except to say that -- except to ask, I suppose, is this the last of the 08 IEPR workshops, Ms. Korosec?

MS. KOROSEC: No. We have another one this Thursday on the accelerating -- excuse me, achieving higher levels of renewables, and one on the evaluation of the PUC self-generation incentive program.

PRESIDING MEMBER BYRON: Of course. You know, I really do that for the Chairman's benefit, because I know how much she enjoys these workshops.

I will make one comment, and that is that the procurement's extremely important. It's tied to many of the policies that we have here in the state with regard to energy. And we identify many of those in the Integrated Energy Policy

Report, and will be re-identifying them.

I think procurement links many of those policies together. So, extremely important topic. Thank you for organizing the workshop. I will turn it over to my Associate Member for comment.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you, Commissioner Byron. I would just offer I think there are people here who are wondering why we're doing a workshop on procurement, isn't that the PUC role.

Well, in fact, it's both of ours, and we have different interests, but we share certainly the concern that the electricity supply in California is reliable and least costly, as well as meeting other goals such as renewables.

So, we're vitally interested in the subject, and I look at this as an opportunity to learn and explore some of the issues. So, thank you.

PRESIDING MEMBER BYRON: Good.

MS. KOROSEC: All right, with that we'll begin the staff presentation. Mr. Vidaver.

MR. VIDAVER: Thank you, Suzanne. Good morning, Commissioners.

My presentation today is largely a

summary of the activities both to date and planned in the CPUC's 2008 and 2010 long-term procurement proceedings.

It will focus on activities that relate to the recommendations of the 2007 IEPR, and potential procurement and planning-related topics for consideration in the 2009 IEPR.

As the latter include environmental considerations in long-term procurement and planning for California's energy future beyond the ten years currently covered by utility procurement plans, these topics are explicitly called out on this outline.

The presentation concludes with a request for comments on and proposals for reducing he likelihood that the procurement process will select development projects that present significant siting and environmental issues.

The 2007 IEPR recommended that Energy Commission Staff collaborate with their counterparts at the CPUC in a long-term procurement proceeding in order to develop a common methodology for the IOUs' ten-year procurement plans.

The IEPR recommendations mirrored the

concerns of other stakeholders. Comments on the 2006 plans indicated a belief that the plans failed to adequately consider significant ratepayer risks, notably those tied to natural gas prices and potential regulation of GHG emissions.

The parties also noted that comparing plans across utilities, and aggregating them in any meaningful fashion was hindered by the use of different input assumptions, output formats and reported performance metrics.

The IEPR also called for extension of the time period considered by the plans beyond the ten years currently evaluated.

The 2008 IEPR scoping order, as noted in the introduction, calls for a report on the status of the collaborative, an examination of selected additional planning and procurement-related topics.

The first two bullets on this slide would be topics of discussion in this presentation. Later this morning Mike Ringer will be discussing the use of social discount rates as they apply to fuel cost streams in the context of planning and procurement.

The final bullet is one upon which staff is seeking input. One of the reasons for this workshop is to elicit public comment on investigation and analysis of these and other planning and procurement issues that should be considered in the 2009 IEPR.

So, let's turn to the proceeding. Before discussing the details of activities in the long-term procurement proceeding it's perhaps best to locate the proceeding in time and place, as it were.

The 2008 proceeding, which will run into 2009, has been divided into two phases. The first phase is addressing research planning-related issues that must be resolved before the ten-year procurement plans can be developed.

These include the issues of standardization and choice of analytic methodology raised in the 2007 IEPR, and comments on the 2006 plans, as well as issues surrounding the consideration of GHG regulation in the resource planning process.

In most proceedings phase two is not planned, appearing only when parties come to realize that there are some issues that have no hope of being resolved in a timely and amicable fashion.

In the 2008 long-term procurement proceeding phase two was set forth at the outset, earlier this year; is expected to open within the next couple of months and be concluded early next year.

It includes issues related to RFO design and execution that need not be resolved before directions regarding ten-year plans are issued in or about April 2009. This, of course, makes these good candidates for an ad hoc phase three, should they prove to be really contentious.

What is noticeably absent from the 2008 long-term procurement proceeding is a ten-year procurement plan, reflecting the importance the CPUC is placing on resolving the issues raised in the 2007 IEPR and in response to the 2006 plans, before issuing directions to the utilities regarding their next filings.

A primary purpose of these plans is to determine the amounts and types of energy and capacity products needed by the utilities over the planning horizon in addition to those that are soon to be provided by target levels of preferred resources.

The CPUC develops targets for renewable energy, energy efficiency and demand response. The residual need for energy products after these targets are met determine the amount of energy and capacity as procurement is authorized.

For example, it is expected that the utilities will be asked to assume energy savings from efficiency programs based on the interim goals established last month in DO8-07047. Similar targets will be set for renewable energy and demand response.

In addition to estimates of resources needed to meet bundled customer demand, the utilities will also provide assessments of the need for new generation capacity in their service territories. Based on assumptions about demand growth for both bundled and direct access customers, capacity savings from energy efficiency and demand response programs, and the retirement of existing aging facilities.

The cost of this capacity, if not procured in the form of utility-owned generation, will be recovered from both bundled and direct access customers.

I'd now like to turn to a discussion of

the standardization that will be imposed on the 2010 plans as recommended by the 2007 IEPR. It extends across the five dimensions listed here.

While the next few slides discuss these in a bit more detail, a brief description of each may make the subsequent discussion a bit clearer.

Input assumptions for what I will call a reference case include, for example, loads, fuel costs, the costs of developing conventional and renewable resources, et cetera.

The utilities will develop a preferred portfolio of resources, including energy efficiency and generation resources, for this reference case. This preferred portfolio will balance costs, risk and environmental factors.

Sensitivities consist of varying individual input assumptions to test the robustness of this preferred portfolio. For example, natural gas prices can be substantially increased to assess the impact of higher prices on the cost of the portfolio.

Output reporting includes a common format for reporting results so the parties can easily sum the results for the three utilities. Performance metrics for the portfolio, total cost, total emissions, et cetera, are those numbers used to compare portfolios and select the one or ones that are preferred.

Scenarios are changes in several input assumptions, changes that reflect the specific future state of the world, as it were. These might be a high carbon cost world in which natural gas prices are higher and greater amounts of energy efficiency are economic.

Scenarios are characterized by an internally consistent set of assumptions that reflect the unique future. As different scenarios are modeled, different preferred portfolios arise.

And finally, the analytic methodology refers to the process of selecting the preferred portfolio for each scenario, and choosing the preferred portfolio across each of the scenarios modeled.

The planning process will yield one or more preferred resource portfolios for each of the utilities. The composition of these portfolios is, in large part, a function of specific input assumptions made, the most important of which are listed here.

Higher load forecast, for example, mean

more resources are needed. Higher gas prices mean fewer gas resources and more energy efficiency, as do high carbon costs. Assumptions about the relative cost of generation resources influence the share of each of those resources in the final portfolio.

By standardizing input assumptions to the extent possible, the end result is plans whose estimated costs are reflective of performance in the specific future state of the world. And can thus be easily compared across utilities.

There are limits to standardization. Where it's inappropriate, it won't be required. For example, conventional resource costs in the L.A. Basin are higher than elsewhere due to the need to purchase offsets. So Southern California Edison, in their plan, will assume higher costs for generic conventional resources.

And where a utility believes that a nonstandard assumption has merit, they will be encouraged to use it in additional analysis.

The 2007 IEPR noted that the 2006 plans failed to adequate consider ratepayer risks associated with natural gas prices and carbon costs. In order to test the robustness of portfolios, the changes in input assumptions, the inputs that are significant drivers of portfolio cost and composition will be systematically varied.

Now, in the best of all possible worlds we'll try and take a gas price and figure out what the 90 percentile gas price and the 10 percentile gas price is based on some sophisticated analysis of historical data. However, this not only takes time, many parties question the validity of historical data in estimating future trends of the values of variables.

For example, why should historical data related to offset prices or carbon prices in the European Union provide any indication of how offset prices in California might behave. And many parties have noted that empirical estimates of gas price volatility based on historical data are liable to under-estimate future gas price volatility.

The one thing that we are certain of is that these sensitivities will include broad enough ranges of values to adequately reflect the risks that ratepayers face. And they will be standardized, so that when each of the utilities assumes a high gas price, for example, the results will reflect a single high gas price, and thus allow the portfolios to be compared across the three utilities.

The reference case load forecast will be that developed by the California Energy Commission. The same high and low cases will be used if sensitivities are run on the load forecast. It's anticipated that the range will cover not only economic and demographic uncertainty, the major drivers of historical forecast error, but policy uncertainties, as well.

So, instead of a high load forecast that is 3 or 4 percentage points above the reference case forecast, one that is 6 or 7 percentage points above the forecast might be used. The point of doing this is to eliminate the need for sensitivities and scenarios to handle every policy contingency that might arise.

The reference case natural gas price will be based on a single, yet to be determined, methodology. The MPR methodology has been suggested. In any case, early year prices are expected to be drawn from the same day's forward strip. This graph presents an argument for assuming a very broad range of natural gas prices for sensitivity analysis, an argument the CEERT has made repeatedly in the proceeding, and one that is supported by a large number of parties.

As at least one of the scenarios to be evaluated by the utilities will include at least 33 percent renewables by 2020, it is all the more imperative that a consistent and plausible set of assumptions be made about the renewable resources in portfolios, and their estimated and potential costs.

In order to facilitate this, a consultant hired to assist staff in the proceeding, E3, is working with the output of the RETI process. E3 intends to characterize possible, if not likely, renewable resource development in competitive renewable energy zones, as identified by RETI, as well as the range of potential development costs. The utilities will then use this information to inform their 2010 plans.

We now turn to output metrics. In order to compare resource plans against one another a complete set of performance metrics, those that will be used for the comparison, is needed.

Stakeholders are still being polled as to the set of performance criteria that should be used to evaluate the plans.

Clearly cost is a consideration. Net present value portfolio cost is a number in the billions of dollars. The levelized average retail rate would make the import of cost differences more transparent in such a large number. The levelized average bill would not unduly penalize portfolios that lead to higher rates solely because of the inclusion of more energy efficiency.

The range of costs, given sensitivities and portfolio risk, is also a consideration in keeping with the recommendations of the 2007 IEPR. The level of CO_2 emissions is, of course, an important factor in evaluating a proposed portfolio.

Reliability is important, as well. But it's likely to be modeled as a constraint, plans having to meet a planning reserve margin.

When all is said and done, the list of performance metrics is not apt to be very long. The more criteria used to evaluate resource plans, the more difficult it is to compare them in a consistent fashion.

Utilities will be asked to develop portfolios for the same set of futures. In standardizing the scenarios that are modeled by the utilities, parties will be able to compare the impact of different futures across utilities. So each utility will model, hypothetically, a 33 percent renewable scenario, a high GHG cost scenario and a high gas price scenario.

And the scenario will be identical for each utility. The scenarios, themselves, will be different enough so that each is likely to yield a different preferred portfolio.

As I mentioned earlier, stakeholder input on the desired set of scenarios is still being sought. There are limits on the number that can be run, and it's not yet obvious how the preferred plan for each scenario will be selected.

How preferred plans will be selected and ranked remains a largely open question. This is, of course, a somewhat subjective undertaking. Portfolio analysis allows you to compare different resource plans with respect to cost, risk and environmental factors.

But because these are likely to be

trade-offs, no one portfolio will be best on all counts. The policymaker is still faced with the task of selecting a portfolio based on some implicit weighting of criteria.

I am now going to segue rather poorly and quickly. The Commission has asked that staff provide a brief review of the manner in which environmental considerations enter into the resource planning and procurement processes.

In resource planning the CPUC is charged with evaluating resource plans based on a number of metrics that jointly reflect the tradeoffs between possibly conflicting objectives. These are cost, risk, reliability and environmental factors.

Environment factors are dealt with directly by using CO2 levels as an output metric. Resource plans are evaluated with respect to total CO2 emissions, or emissions intensity.

As a result, regulators can weigh the tradeoff between GHG emissions on one hand, and cost on the other.

They enter directly into the portfolio cost calculation through assumed CO2 costs. Higher emissions portfolios, all else equal, are higher cost due to the carbon cost that utilities will be told to assume in the 2010 resource plans.

And finally, carbon risk is considered. Portfolio costs will be evaluated over a broad range of carbon costs.

In procurement, where utilities are choosing between resources offered in an RFO, a GHG adder is used to compare resources. This value was endorsed several years ago and may seem low, but it's not really had any impact to date.

Utilities have had a need for dispatchable resources during the past several years, limiting the extent to which conventional and renewable resources have actually been in competition in RFOs.

Note that there is --

PRESIDING MEMBER BYRON: Mr. Vidaver.

MR. VIDAVER: Yes, sir?

PRESIDING MEMBER BYRON: What's the units on the bottom, the GHG adder, $8.

MR. VIDAVER: It's $8 per megawatt hour, I believe, from the resource in question. Sorry about that.

PRESIDING MEMBER BYRON: Okay, thank you.

MR. VIDAVER: It's now, at this escalation rate I think for plants that come online it comes out to about 10.70.

Noticeably absent from this is in the RFO process is any consideration of local environmental issues, criteria pollutants, et cetera. It's assumed that these issues are all handled in the Energy Commission's siting process.

The likely treatment of GHG uncertainty in the 2010 plans will be to assume a carbon price and use sensitivity analysis to test the robustness of portfolio costs to changes in the carbon price.

A more sophisticated modeling effort in which explicit assumptions are made about the cap-and-trade regime that might be imposed would require assumptions about the items listed under the first bullet here, as well as the relative costs of reducing GHG emissions across capped sectors.

When more details about the cap-and-trade regime are known, modeling for resource planning will no doubt incorporate them. But the 2010 plans are likely to be limited to use of a single carbon price, and range of carbon prices in evaluating the portfolios.

The 2007 IEPR recommended that the procurement plans submitted by the utilities extend over a 20- or 30-year period of analysis. On July 10th parties in the long-term procurement proceeding were polled as to the need for the utilities to provide portfolios, or assessments of portfolio performance that extended beyond 2020.

If a party believed that such analyses were necessary, it was asked to describe the purpose of the analysis it proposed. The next few slides are going to summarize some of the replies, rather tersely.

PG&E noted that the uncertainty of scenario inputs, load, fuel cost, development costs, et cetera, as well as regulatory uncertainty severely limit the value of analysis beyond 2020.

San Diego Gas and Electric's reply was similar, highlighting uncertainties surrounding changes in technology, and pointing out that a different set of analytical tools than those currently used for the long-term procurement planning is necessary.

Southern California Edison allowed that

decisions made in the next ten years could have a significant impact on the mix of generating assets in the following decade. But that uncertainties beyond 20 years limit our ability to act effectively now in response to the set of possible futures that we might face.

The analysis implied is one in which attempts to envision where we might want to be in 2030, and that evaluating present-day alternatives, in part, in light of how they impact our ability to get there.

CEERT comments focused on the need for any analysis, regardless of length, to consider the likelihood of very high gas prices. Of the analysis it recommended, one scenario extended analysis through 2030, recommending an extrapolation of preferred resource additions for ten years beyond 2020. And an estimate of the resulting GHG reductions.

The recommendation here focuses on estimating the GHG reductions, and not on the costs of such a portfolio. Although I imagine that CEERT and many others would expect that given high gas prices, the value of GHG reductions and advancements in renewable technology, that this portfolio would be preferred to an alternative that contained lesser quantities of preferred resources.

And finally, NRDC, UCS posits that focusing on meeting the AB-32 emissions limit for 2020 may lead to near-term investments that differ from those that would lead to the most cost effective portfolio needed to meet more distant targets.

They also believe that data projections for key assumptions are of sufficient quality so as to allow parties to focus on least-cost portfolios through 2030, rather than the current 2020.

Now, I'm reticent, as a member of joint staff in the procurement proceeding, to make statements regarding the likelihood or desirability of the CPUC extending the planning horizon to 20 years or more.

Rather than doing that I would prefer to offer general observations about procurement planning and forward-looking analysis over a 20-year or longer period.

The purpose for my doing this is neither to lay the groundwork for any specific staff proposal for longer term analysis in the 2009 IEPR, nor to recommend specific direction be given in the procurement proceeding, but to provide material for parties here to respond to, if not today then in post-workshop comments.

As I stated at the outset of this presentation the purpose of this proceeding is to elicit comments regarding what types of analyses should be done in the 2009 IEPR.

I'd like to begin by discussing some of the major post-2020 uncertainties, many of which are of much lesser magnitude in the near term. For example, we can be relatively certain of the rate of load growth through 2020 compared to later periods, given assumptions about energy efficiency expenditures. Although I imagine your demand forecaster would disagree with this statement.

Electrification of the transportation sector is almost certain to raise the growth rate in the longer term, but by an amount that's very uncertain. Properly incented, this will raise offpeak loads, influencing the need for baseload and dispatchable generation.

Technological change is the biggest uncertainty, one that is not a major consideration in the short run. Changes in the relative costs of energy efficiency and renewable generation, as renewable technologies mature, will influence the desired composition of preferred resources.

Different rates of technological advance may dramatically influence the composition of renewable resources. Advancement in solarvoltaic and smart grid technologies may move renewable energy generation from ridgetops and remote desert regions to rooftops. Advancements in storage technologies may help to move them back again.

The availability of clean coal and nuclear generation become an uncertainty once we move out beyond 2020. One that does not lend itself to numerical analysis. While we can come up with ranges for their costs, their inclusions in the portfolio of tomorrow depends on a host of factors that drive the potential for and cost of lowering greenhouse gas emissions without them.

This uncertainty means that it's difficult, to say the least, to develop least-cost portfolios for 2030 and beyond. And while we know that California has a GHG reduction target of 80 percent below 1990 levels by 2050, we do not know the extent to which this task will be borne by the electric sector, much less individual utilities.

Depending upon reductions extracted from other sectors of the economy, GHG reductions in the electric sector may be more or less.

If our goal is to reduce our reliance on carboniferous resources, we've taken a large first step with the emissions performance standard, which precludes long-term investment in coal-fired generation absent carbon sequestration.

But unless energy efficiency offsets all peak load growth, there remains a need to invest in gas-fired resources in the near and medium term. Renewable resource that provide significant capacity value are currently not being provided at a rate needed to maintain reserve margins.

Some share of the capacity needed to meet demand growth much be dispatchable. Dispatchable renewable generation is in especially short supply. Much of renewable generation is currently remote, unable to contribute to local reliability needs.

As we retire aging power plants in local reliability areas we will largely replace them with dispatchable gas-fired resources.

And finally, the increase in

intermittent generation requires dispatchable backup. And while hydro resources can support intermittence, the experience of the northwest indicates that there are limits as to its ability to do so.

Over the long term our need for these resources, hopefully reduced need, is driven by technological change and choices regarding infrastructure. Wind turbines that perform better at low wind speeds to reduce the need for dispatchable backup. Low-cost biofuels to allow for large quantities of dispatchable, clean generation. Storage technologies, and, of course, transmission.

This is not to say that we should ignore short-term procurement decisions. We need to monitor the procurement of new gas-fired resources and develop transmission to insure that they're designed and located so as to reduce the need for such resources five and ten and even 20 years from now.

I would propose that the search for answers to three questions might be considered as staff thinks about utility resource planning. Earlier I presented a recommendation that CEERT posed in comments in the long-term procurement proceeding. That estimates be made of the GHG reductions that would result if preferred resource targets were linearly extrapolated from 2020 to 2030.

This is a good start. But coming up with an accurate estimate probably doesn't require a sophisticated data-intensive model. Of equal and greater interest is how far GHG emissions can be reduced by utilities given current technologies and infrastructure, and assumptions about the set of renewable resources that will be built over the next five to ten years.

An assessment of how the constraints that require gas-fired resources might be loosened when offered insight as to the potential and potential cost of lowering GHG emissions even further. And the results of this inquiry will shed light on the possible need for and potential benefits of clean coal and nuclear generation.

That concludes the presentation with one small addition. In the RFO process used to select projects that the IOUs will contract with or take over after construction, utilities are faced with offers from projects in various stages of development. Some are permitted; some are built; others have yet to complete the permitting process.

The CPUC has instructed the utilities to consider viability, and more recently, the possession or lack of a permit, in evaluating the offers they receive. And there is no doubt that they do so.

Yet several projects have been selected that presented significant siting and environmental issues. For example, the site, for one, was not appropriately zoned. The applicant was forced to withdraw when he was unable to get local authorities to rezone his site.

Another initially approached the Energy Commission with a proposal for cooling water usage that seemingly ignored prior Commission statements regarding the limited circumstances under which usage would be allowed. The project was delayed as a result.

The selection of projects is no doubt a complicated undertaking with low costs and desirable operating characteristics being balanced against greater risk that the project cannot be brought online in a timely fashion.

Nevertheless, because of the adverse reliability consequences of delays and terminations, staff is seeking comment from parties on how the procurement and permitting processes might be better aligned so as to limit the frequency with which these problems arise.

And that completes my presentation. Thank you. I hope I didn't speak so quickly as to preclude questions.

PRESIDING MEMBER BYRON: That was kind of quick, Mr. Vidaver. Could you repeat the presentation, please.

(Laughter.)

MR. TUTT: At half speed.

PRESIDING MEMBER BYRON: At half speed.

So I'll start with a couple of questions, if I may. Not with regard to the presentation so much, as just general, additional general information that might be helpful.

We talk in our IEPR about the importance of consistency. The long-term procurement plan should use common assumptions across utilities. Can you speak to that a little bit? Can you give us a sense of whether or not we've, indeed, achieved that in your review of the various procurement?

Also, what about some of the unique requirements that come out of procurement, one that I see occasionally, if not all the time, is that it be new construction that be procured, that kind of thing.

MR. VIDAVER: As noted in one of the slides, the planning process is -- the procurement plans are divided into what is basically an AB-57 component which is designed to shed light on the bundled customer need, the contractual need of the individual utilities. And a separate component, in which the utilities do assessments of the need for new capacity in their service areas, given assumptions about load growth, demand response, energy efficiency and what power plants will be retired.

As part of the AB-57 component, the utilities develop plans making sort of input assumptions. I would guess that -- little better than a guess, that consensus has been reached on how all of these are going to be handled.

The utilities will use the CEC reference case load forecast. If they do a sensitivity of high and low loads, they'll use the same percentage changes so that the impact of an unspecified policy that reduces load by 2 percent or increases load by 4 percent can be compared across all the utilities.

They will be required to use the energy efficiency targets established in the DO8-07047. They'll be required to use the same gas price forecast, but by that we don't mean that they'll all use $7.42. They'll all use the forward price, as it were, on the specific date, adjusted for basis or the cost of transporting the gas from, in San Diego's case the cost of transporting the gas from the SoCal border to San Diego, which I don't know the value. But their gas price forecast might routinely be 8 cents or 20 cents higher than Southern California Edison's.

The electricity price forecast, we've all agreed, that they can use different values. The way they develop that methodology they use is slightly different for Southern California Edison. It's not a very -- well, it's a key assumption; it's very easy to verify that the assumption is -- the veracity of the assumption that's made. Parties can very easily go in and check to see that, given the gas price, the market electricity price assumed by the utility really does reflect an accurate value.

The utilities will all be told to assume the same carbon cost, a high or low. And the same high or low carbon cost. As I mentioned, they'll be told to assume the same conventional resource cost, but the cost of developing combined cycle in the L.A. Basin is going to be higher because of the cost of obtaining offsets there. So Southern California Edison will use a slightly higher value in their analysis.

And the renewable resource buildouts and costs are going to come out of the analysis that E3 is doing, based on the RETI report. The utilities will be allowed -- E3 is actually going to go in and posit what's going to be developed where. And what a reference case cost for that is. And the utilities will effectively be required to build out their portfolios based on the set of resources that RETI -- that E3 comes up with.

If RETI posits a range of potential development costs for let's say wind generation, then the utilities, in doing sensitivity analyses will have to use those high and low values in estimating the potential range of ultimate development costs.

I imagine -- there are other things that are pretty easy to standardize. Use of the -- the inflation rate use, for example, is going to be standardized. But that really doesn't have much of an impact on the portfolios that you produce.

So, there's a great deal of standardization. And as I said, the utilities, if they firmly disagree with a kind of reference case forecast for any of the important variables, they're encouraged to explain why they think that value's incorrect; and do analysis using another value for that variable. They have to do analysis using that reference case value that can present alternative values, if they so choose.

As far as new generation is concerned, this is -- the utilities have to make assumptions about load forecasts and energy efficiency and what they can get from -- the capacity savings that they can get from demand response. And these are all pretty well set, as you can see.

The differences in assumptions largely come down to what the utilities assume are going to be retired. Now, there was some talk about requiring a priori the utilities would have to assume that the following plants would be retired in their service areas.

I'm not certain that this is going to be the case. It requires that some benevolent dictator, say, make the following assumptions about plant retirements. If you allow utilities to use their own assumptions, it's very easy to check and see. They assume that plants A, B, C and D are going to be retired. And the impact of retiring an additional plant, or not retiring a plant is very transparent and easy for anybody to calculate.

So, if a utility assumes that a brand new power plant is going to retire, and therefore that it should be allowed to procure capacity on behalf of all customers to replace that, I imagine that the PUC would -- that plant's not going anywhere.

And the decisions about which plants are going to be assumed to be retired, and therefore the amount of capacity that the utility can procure on behalf of all customers is something that's discussed in hearings. And all parties can provide testimony as to whether or not those assumptions are reasonable.

In the 2006 plans the utilities were asked to assume that the aging power plants that came out of the 2004 report by the Energy Commission were retired. So all of those plants in northern California were retired by 2015. All of the aging power plants in southern California were retired in a staggered fashion over 2015 to 2018. And the amount of new generation which utilities were allowed to procure fell out from those assumptions.

So, I would imagine that the State Water Board's rule will be a consideration in developing the amount of new generation that will need to be built, and possibly funded by the utilities.

The Public Utilities Commission, a couple of years ago, realized that energy service providers simply did not have the capital to construct new capacity. So it required that the major investor-owned utilities fund new capacity. And then allocate the costs of that capacity to energy service providers on a pro rata basis, with the energy being auctioned off after the plant was constructed.

And the utilities will be quick to point out that they were only authorized cost recovery for those plants being built on behalf of all customers for a ten-year period. And this is a kind of sore spot. They think that if 92 percent of a power plant is being built, and only 92 percent of a power plant is being built, to meet bundled customer needs that they should be entitled to recover that 92 percent beyond a ten-year period.

I hope that doesn't further muddy the waters. I apologize.

PRESIDING MEMBER BYRON: Thank you. You know, you cited some cases from recent siting projects at the Commission. And it brings to mind the fact that there's, you know, there's other potential issues that will arise here over the course of time. Issues that are difficult to assess when doing procurement. The priority reserve issue in southern California. Sometimes developers are somewhat new to California, maybe not experienced with the thoroughness of our process and some of the environmental concerns that you raised.

Do we, as a Commission, do we look at any of these kinds of issues -- I'll ask this a little bit differently, David. We've got a number of large land use applications that may or may not come before the Commission. A lot of renewable projects that are thermal will fall under our purview and some that will not.

I'm quite concerned about the constituents that we're now seeing in these cases are new to us, new to the process. I consider the ones that are outside our purview high risk for potentially not being able to get through the local siting processes successfully.

Is this also what you mean when you were talking about environmental issues?

MR. VIDAVER: The --

PRESIDING MEMBER BYRON: Environmental issues that weren't necessarily considered in the selection process.

MR. VIDAVER: Yes. Yeah, I did not mean to, in referring to criteria pollutants and local environmental issues, those were examples. I didn't mean to imply that those were -- that was an exhaustive list of the environmental issues that arose in the construction of capacity to meet California energy needs.

I don't work in our siting division. I

understand that a good deal of time and effort is being devoted to making sure that parties know enough about our process to be able to go through it quickly. As well as to look at other processes, BLM, for example, and see how those might lead to problems.

PRESIDING MEMBER BYRON: So there's a lot of things to consider in the procurement process. A lot of things that may be beyond control of the utilities doing the procuring.

What are the consequences if they're not able to, I suppose we'd call that contract failure. What are the consequences if they don't procure sufficient resources.

MR. VIDAVER: Well, in the worst case, lights go out. But we don't tolerate that, so we end up with sort of ad hoc ways of making sure enough capacity comes online soon enough to keep the lights on.

So, we end up with things like emergency peakers being built. As you know, one could go all the way back to 2001 and look at expedited siting processes and executive orders. And more recently, the procurement -- or the request to procure resources outside the competitive procurement process.

So, we end up paying, perhaps, two prices. One is a higher price because we're sort of trying to buy insurance when the house is on fire. And there's also a credibility concern. As more and more of our resources are procured outside of a competitive process, whether justified or not, parties come to question whether or not that process is actually above-board and truly competitive.

PRESIDING MEMBER BYRON: Madam Chairman? Thank you.

ASSOCIATE MEMBER PFANNENSTIEL: David, would you help me understand a little bit about the transparency or the confidentiality, the other side of it, of the information.

Clearly, the standard input assumptions are known publicly, and we work on them, and we all know what they are, and so they go into the input to the model.

But then at some point the decisions that the utilities make on their portfolio, their procurement to their portfolio, at some point that becomes, the cost thereof becomes confidential.

And where is that? At what point -- is

it just the bids that come in, and then the decisions are confidential? But as long as it all fits into what has been modeled then it is deemed by the PUC to be okay?

We lose track of that. And certainly as Commissioners who are not privy to the resource groups sort of see that effect, but we don't really see how the evaluation is done.

MR. VIDAVER: Well, I guess I'd like to divide that into two parts, one being the long-term plan, and the other being sort of procurement and bid evaluation and offering contracts.

One of the advantages of standardizing input assumptions and prescribing the input assumptions that utilities will use in their long-term plans is that they are no longer confidential.

A utility, in using its own gas price forecast, can claim that that forecast is confidential. When you tell the utility what forecast to use, that's now public information.

So, we've come a long way towards making the procurement plans more transparent. There are still elements of the plans that are confidential. For example, the utility, in creating its portfolio, has a model which dispatches all its resources, and it tells you effectively when it's going to run this plan and how much energy it's going to require from this contract, et cetera, that information remains confidential for, I believe it's -- much of that information remains confidential for the first three years of the plan. But we've taken a step forward in making the procurement plan a little more public.

As far as bid evaluation and transparency in how projects are chosen in the RFO process, part of the confidentiality arises from the needs and interests of the bidder, himself. The bidder is frequently -- I don't know if it's part of boilerplate language in RFO documents or in offers, the utilities can address that. But some of the information is kept confidential at the request of bidders.

Regarding the process, the criteria that utilities use, all of the criteria, themselves, are known. Those criteria are prescribed by PUC. Details about how those edicts are interpreted by the utilities are published and are available.

There are a number of criteria which are qualitative in nature, which makes it more difficult to represent the decision in the form of an equation. So, the exact sort of numeric scoring bit is not something that the public is privy to.

As parties testified in the workshop on PRGs stated, believe that some of this information should be kept confidential to insure competitive responses.

There's also a need, I believe, to provide enough information to bidders to let them know exactly what criteria -- it's not so much the criteria, I'm not sure the entire set of criteria that a utility could use in evaluating bids can be anticipated and made public beforehand.

I think it would be a very good idea if the CPUC and others went through the past RFOs and looked exactly at what criteria were used to see if additional criteria could be added to this list that might be considered. I don't think anyone's ever gone back and done a good review of the extent to which the publicly available information regarding bids and their evaluation is as large as it could be.

ASSOCIATE MEMBER PFANNENSTIEL: Back to the question on the standardized assumptions. As you described, I think, quite well, there are some sensitivities in some scenarios that go around each of these assumptions.

Is it public which variation the utility actually uses, and so we know that if there's a high and low scenario or a sensitivity, that in that procurement or in that long-term plan, they will have chosen one or the other?

MR. VIDAVER: Yes.

ASSOCIATE MEMBER PFANNENSTIEL: So all of that is --

MR. VIDAVER: Stakeholders, many of these decisions are mainly discussed in working groups. For example, the issue of load forecast standardization. The working group that was established three months ago said load forecast, CEC load forecast and done.

ASSOCIATE MEMBER PFANNENSTIEL: Right.

MR. VIDAVER: Taking that out to stakeholders in the form of a report which was issued, I believe, in May said we're going to use the CEC load forecast. We've made this decision because we didn't think it was really a contentious issue. Let us know if you have a problem with it.

Which scenarios to model? There are parties who want really detailed specific scenarios that shed light on issues that they or their constituents are really concerned about.

So, the scenarios working group is not even going to meet until stakeholders submit comment on which scenarios are going to be developed. So all that is public information.

ASSOCIATE MEMBER PFANNENSTIEL: So there's a lot of public scrutiny of the input assumptions, but then the alternate process is really up to the utilities, the PRGs and the PUC?

MR. VIDAVER: The PRGs are not really involved in the ten-year procurement plans. The PRGs, I'm speaking from memory, have enough to keep them busy, especially in 2010. There will be so much precise direction given to the utilities that occasionally they may ask the PRG or the energy division as to whether or not certain way of presenting that information is sufficient.

ASSOCIATE MEMBER PFANNENSTIEL: So the PRGs, and this is just a confusion on my part, having been one of them, don't look at the procurement in the context of the long-term planning?

MR. VIDAVER: No.

ASSOCIATE MEMBER PFANNENSTIEL: Oh, they're independent. I thought that the long-term plan would guide the PRGs work. Not so.

MR. VIDAVER: Well, the long-term plan is designed to provide an authorization for the utilities. You can go out, and we've looked at your plan, we've approved it with substantial modification and a little berating, but you can go out and you can get 500 megawatts of baseload capacity starting in 2012 and 150 megawatts of peaking capacity in each of 2009 through 2014. At least 400 of this has to be new generation. And it should also be located in the L.A. Basin. That's what the procurement plan comes up with, or when the plan is approved.

Authorization to procure those amounts are given. The utility then has an RFO where it goes to the PRG and says, here's the description of what we're going to provide bidders and what we're authorized to procure.

The bids come in. Here are the bids. Here is how we evaluate them. We proposed that we sign the following contracts. And the PRG, either makes recommendations about additional contracts that the utility should consider. Contracts that the individuals and the PRG have problems with.

The PRG is a form in which all the parties that participate get more information about the set of alternatives available to the utility, and to get it before, usually months before, the utility actually makes its final proposal.

And gives a heads-up if a particular party says sorry, we're going to litigate that, the utility takes that into account. And may either withdraw the proposal to enter into the contract, or say, see you in court.

ASSOCIATE MEMBER PFANNENSTIEL: Thanks.

MR. VIDAVER: Thank you.

PRESIDING MEMBER BYRON: David, I think we could go on asking a lot more questions. I think in the interests of time we'll let you off the hook for awhile.

Does anyone else have some questions for Mr. Vidaver? Please, come forward. And if you'd be so kind to identify yourself.

MR. BAKER: This is Simon Baker from the CPUC Energy Division. And actually I'd like to make some comments, if I could, if this is the proper time to do so.

The 2007 IEPR recommendations were very much aligned with the CPUC's 2006 LTPP decision 07-12052. And the language in that decision calling for greater standardization of resource planning assumptions and a move towards a more rigorous planning process in general.

We're very grateful for the CEC Staff and its participation as a collaborator in the 2008 LTPP proceeding, which has taken up those recommendations in earnest. And is in the middle of a thorough stakeholder process to develop a decision acting on those recommendations.

CEC Staff has been very valuable in our process in championing the CEC's vision, I believe, in the 2007 IEPR; in clarifying some of these very complex issues; and in bringing a level of expertise, which is, I believe, second to none, in planning and procurement and analysis in those areas.

What we have before us in the 2008 LTPP proceeding is potentially infinite scope. Resource planning is inherently complex and difficult. You're making multi-billion-dollar investment decisions looking out 10, 20, even longer years. Assets that last 30 years or more.

And particularly today, when we have the challenges of AB-32 and renewable energy goals like 33 percent. The number of different scenarios or sensitivities that you could potentially run in a planning analysis are truly infinite. And the number of different techniques that you could use to develop meaningful results and present the information to decisionmakers in a discrete, understandable, meaningful way is something that walks the line between art and science.

As I said, the 2006 LTPP decision recognized that there was a gap in the level of rigor and standardization that needed to be closed. And in looking at the work before us, the Energy Division is recognizing that it may take a couple planning cycles for us to really get to a place with planning standards that we think is cutting edge and representative of the best planning practices in the industry.

As an example, the first thing that we tackled in some of the working groups that Mr. Vidaver mentioned was simply just getting the three utilities to utilize the same table format in representing their loads and resources to determine the net -- calculation.

It seems like a very mundane thing, but those are the baby steps that we're starting with here.

So, recognizing that some of these planning standards and techniques may occur for application in the 2010 plans, and others, which may take more time to develop, may require more software, modeling capabilities. May require scale-up in staffing at the utilities to be able to do these types of sophisticated analyses. Some of those techniques may end up as recommendations for the 2012 planning cycle.

So, Mr. Vidaver did an excellent job of summarizing the status to date in the 2008 LTPP proceeding. And I really wouldn't add anything.

He had the difficult task today of peering into the crystal ball. Because, as I said, this is an open and active proceeding and no decisions have been made yet. And so he's really trying to get that gestalt sense of where the proceeding is going. But, as you know, things can change before a final decision is reached.

I'll give a little bit of background on

the overall process that we're involved in in the 2008 LTPP proceeding. Dave mentioned that a working group was established early on in the process. That was the planning standards working group.

And that was where joint staff me with utility representatives to learn from the utilities about their planning practices. And to get a sense from them of what the scope of standardization might be. And get a feel from them about what assumptions and what-have-you are appropriately standardized and what may not be. What may be more trouble than it's worth.

That working group culminated in a pre-workshop report. And parties had the opportunity to review and comment on that at a workshop in May, May 21st.

At that point, we took a hiatus and brought on a technical support consultant, a consulting team, Aspen and E3. And they were brought on at the end of June.

Now, they're playing an important role in this proceeding, because, as I mentioned, this is a highly technical and complex area. And they're bringing that expertise.

So what they're producing for us is really two deliverables that are germane. The first is they're doing a best practices review of industry planning practices. And they'll be producing that as a consultant's report on resource planning best practices.

So that's really going to be casting the wide net of all of the different approaches and analytical techniques that are taking place out there in the industry, so that Energy Division and the CEC Staff and parties can learn and try to understand better which of those tools are appropriate in the California context.

We've also established working groups to assist the consultants in developing their second deliverable, which is going to be a consultant's straw proposal on resource planning standards.

So the role of the working groups is really to inform the consultants' straw proposal. And that straw proposal will be served on the service list and a workshop will be held. And parties will again have the opportunity to provide their input on that straw proposal, which will then inform a staff proposal on this same topic, on resource planning standards.

When the staff proposal is filed into the docket that will really initiate the development of the formal record on planning standards in 2008 LTPP proceeding. And there'll be comments and reply; and then a PD and comments and reply before final decision.

At this time also I'd like to just announce that Energy Division plans to host a workshop on August the 28th on scenarios and metrics. And we have issued a data request to parties for comments on really at a high level what some of the guiding principles for developing such standards should be in this process.

And also giving parties a chance to submit specific lists of scenarios that are developed to a very high level of detail, which will then be discussed at this workshop.

The workshop, the purpose of it will be to then kick off a working group which will further develop this, leading into the consultants' straw proposal, the staff proposal, and then eventually a decision on planning standards in the proceeding.

Finally Mr. Vidaver, I think, made the appropriate statement with regard to the LTPP proceedings direction, or not the direction, but where we seem to be headed on the question of the proper planning horizon for the LTPP proceeding.

No determinations have been made on this issue, along with others. But really, just to give you a sense of what we're grappling with, because we have so many of these standards to put in place, and we're really going to be developing scenarios from the ground up. So it's a very broad scope and we recognize we have a schedule we need to maintain to be able to then feed into the 2010 LTPP proceeding.

So, as you push out to that 20-year planning horizon, many comments from parties indicate that you might use a different set of tools, analytical tools to assess uncertainties in that horizon.

And to the extent that those analyses are somewhat distinct or separate from a look out to 2020, we've been looking at key uncertainties such as the effect of plug-in hybrids and electrification of the transportation system, the potential of emerging technologies like storage, low wind speed technology, carbon capture and sequestration, potential cost reductions in renewables such as PV and wind, if ever grid parity may occur.

Smart grid technologies. The potential of reduced ability of large hydro due to climatic change impacts. Competition from renewables from other states.

Really, the nexus between energy use and water use, pumping and so forth. What federal GHG policies may look like. And also the effects of once-through cooling on planning for reliability.

This is a very big scope. And frankly, we're here to ask for your help at the CEC to help us to do some of these important analyses that we have on our radar screen. We recognize that they're important, but we're also managing scope of what we can do in the 2010 LTPP proceeding.

So, to the extent that the 2009 IEPR takes some of these issues up and treats them in an analysis that could be conducted in a collaborative with our Commission and with the IOUs, as they develop their own 2010 LTPPs, we see that as a potentially fruitful collaboration to address these issues in some fashion in the 2010 timeframe.

Thank you very much.

PRESIDING MEMBER BYRON: Mr. Baker, thank you very much for being here, and for that description about your process. You have your process, we have our process, there seems to be no shortage of that at state agencies.

But it's very helpful to me. I want to understand schedule a little bit. To the extent you can, -- well, first, let me just comment, too, on the collaborative aspect of the work that the two Commissions are doing on long-term procurement.

I know that we've collaborated before on various issues. And I think this is another excellent example of how the state will benefit from the coordination of your needs, the requirements for controlling cost to consumers, and implementing state energy policy.

You had mentioned some of the workshops that are coming up and how this will all eventually lead towards a final decision. Can you give us a sense as to when that final decision will be -- I don't want to hold you to a schedule, I just want to get a sense, are we talking this year, a year from now, et cetera.

MR. BAKER: Yeah, well, we appreciate

the need for flexibility on those types of --

PRESIDING MEMBER BYRON: And I'm not sure you could speak for the Commission, but --

MR. BAKER: I can't speak for the Commission, but as Energy Division has been planning this out, we have been thinking about a first quarter 2009 timeframe for a final decision on planning standards.

And I should also note that that final decision will be a decision on phase one issues in R08-02007. And phase one issues are broader than just this planning standards question.

For example, the Commission has identified the need for looking at MRTU-related procurement products and the need for developing upfront standards of that to provide guidance to the utilities as they develop their 2010 plans, as well.

PRESIDING MEMBER BYRON: One other question. You also gave reference to some contract work that you're using for getting access to expertise. I came across a report I was not aware of that published just earlier this month.

And I bring it to your attention in the event yo haven't seen it. It's a NARUC report that was funded by the Department of Energy. Are you familiar with it? Competitive procurement of retail electricity supply, recent trends in state policies and utility practices.

MR. BAKER: Not familiar with it, but I would appreciate the reference.

PRESIDING MEMBER BYRON: Absolutely. I call it to your attention and I think it's easily accessible on the web. And it's extremely good, because it does a state-by-state kind of comparison of various procurement processes.

I was really pleased to read that it helps vindicate some of the recommendations in our earlier IEPRs. I think it would be very helpful to your proceeding. So I'm pretty sure our staff is aware of it, is that correct, Mr Vidaver?

MR. VIDAVER: I can forward Mr. Baker an electronic copy.

PRESIDING MEMBER BYRON: Okay. And so I'll avoid asking questions about it since you're not familiar with it. Any questions from my fellow panel members?

ASSOCIATE MEMBER PFANNENSTIEL: None from me.

PRESIDING MEMBER BYRON: Okay. I again

thank you for being here.

MR. BAKER: Thank you for the opportunity to comment.

PRESIDING MEMBER BYRON: That was supposed to be just a question, I think, for Mr. Vidaver. And in the interest of time I'm going to ask that we move forward, correct? We have another agenda item, Ms. Korosec?

MS. KOROSEC: Yes, we'll be hearing from Mr. Ringer to discuss social discount rates.

MR. RINGER: Well, good morning; it's a good sign that it's still morning, I wasn't sure whether it was going to be good morning or good afternoon.

I'm going to speak about social discount rates. The 2007 IEPR talked about the California IOU long-term procurement plans excessively discounting future fuel costs by using too high of a discount rate.

The effects of this would be to understate the impact of those fuel costs upon consumers, increasing dependence on gas-fired generation as a result. And by excessively discounting what it meant was using the utility weighted average cost of capital. So always taking into account the utility costs of capital and using that as a discount rate.

The 2008 IEPR Update Committee scoping order directed staff to identify consequences of using a social discount rate. On the surface this is fairly simple. A social discount rate, as we will see, is typically lower than the utility weighted average cost of capital. And by using a social discount rate instead of the utility cost of capital, you effectively raise the cost of gas-fired generation.

But as I said, on the surface this is very simple. It turns out that there is a very complex large body of work that was done over a long period of time on discount rates. Much of it is very esoteric, so what I endeavored to do was put together sort of a simplified overview of a discussion of discount rates.

And congratulations to those of you who made it through my paper. If you think this is dry, this is much moister than the original sources that I looked at.

(Laughter.)

PRESIDING MEMBER BYRON: Moister meaning it made us cry?

(Laughter.)

MR. RINGER: Hopefully not. Very quick background. Interest rates was the time value of money used to determine the future value of a present sum. It's actually determined from outside sources depending on how much you can earn from different investments, whether it be banks, bonds, commercial paper.

Discount rate is essentially the inverse of that. You have a future sum and you want to place a present value on that. The discount rate to be used is up to the particular analyst doing it, based on a number of different factors and points of view.

And as I mentioned, higher discount rates placed a greater value on the present compared to the future. So a very high discount rate essentially means that you're placing a low value on the future. Conversely, if you're using a low discount rate, you are placing a higher value on the future.

I thought it was instructive to look at some different agencies, so I chose the Energy Commission, the Public Utilities Commission and the Office of Management and Budget.

The Office of Management and Budget looked at discount rates a couple different times, one in 1992, and again in 03, I believe.

In 1992 they determined that 7 percent was the real cost of capital in the private sector. When I say cost of capital, that's also an opportunity cost, that's the amount of money that you can earn on an investment. So they looked at that.

The Energy Commission, for our appliance efficiency regulations, did another study. And they looked at the real after-tax cost of capital based on a variety of different sources in the private sector.

They looked at 30-year home loans, $10,000 home equity loan, 7- and 20-year home loans, and then even a credit union VISA card.

So these, although I'm talking about government agencies, and we do hear the term social discount rate a lot, it's not necessary in all cases for a government agency to look at a social discount rate. And, in fact, these are based on private cost of capital, so they are private discount rates. But they do have their place in government agency use.

The Public Utilities Commission did look at discount rates, and they determined that they were going to continue to use the IOU -- the utility weighted average cost of capital rather than social discount rates as applied to transmission projects because they felt that they could more easily compare transmission projects and alternative investments through the use of a single discount rate.

Now discount rates based on the cost of government funds typically are lower than the market risk rate because government can borrow money more cheaply. And this is what we talk about when we mention social discount rates, the cost of government funds.

Governments are also more interested in considering future generations' interest and not discriminating against them. Higher discount rates, as I mentioned, make future costs seem more expensive, and therefore seemingly discounting the interest of future generations too much, and making things seem too cheap.

Social discount rates have traditionally been used for long-lived or public goods projects. Dams are a good example. Sometimes social discount rates or lower discount rates are used as a remedial measure to counteract market externalities or inefficiencies.

And I think one of the good examples of an efficiency there is through efficiency measures. Private individuals typically require a very very high payback, very short payback periods for their investments in efficiency measures. Much more so than people who are investing in power plants.

Therefore, by using lower discount rates to calculate the benefits and costs of energy efficiency measures, we can make that more conducive to people so that power plants don't have to be built.

The Office of Management and Budget, as I said, took another look at this, I think it was in 2003. And in addition to the 7 percent discount rate, they suggested that agencies also use 3 percent discount rates.

The 7 percent was based on when regulation displaces or alters the use of capital in the private sector. Whereas, the 3 percent is when a regulation affects private consumption. So that's the difference there.

Now, in the 2004 IEPR update the Energy Commission recommended using a social discount rate when evaluating transmission investments because the Energy Commission determined that transmission is a public good. The benefits can't be divided among certain individuals, and therefore it behooves the use of a social discount rate.

When you look at the literature that I referred to there's quite a bit written, it becomes very confusing very quickly because you come to the realization that a lot of people want to use different discount rates for different risk and a lot of people don't.

So there's two basic views. Discount rates should not be affected by the uncertain or risky nature of future cash flows, or that they should be adjusted for risk to reflect the uncertainty of the cash flows so that the high risk returns are discounted more, and the high risk costs are discounted less.

Now it turns out that a pretty good way to look at this is to see whether or not there's a difference in finance theory or decision analysis. This was based upon some writings by the Electric

Power Research Institute in the mid 80s where they took a look at these questions. And it framed the idea pretty well in my mind as to what the arguments were pro and con of adjusting discount rates for risk.

EPRI discussed finance theory and decision analysis and made some observations. Finance theory pretty much takes the perspective of a private investor, how much risk is a private investor willing to take and how much do they want to be compensated for that risk.

We all know that the riskier an investment in general, the higher rate of return you would expect from that investment. So finance theory tends to look at project-by-project comparisons from the investor's point of view; considering the market value of those investments, and applying a risk-adjusted discount rate to a single expected cash flow. This is fairly important.

So, if you're comparing one project to another, and you have different cash flows associated with each project, if one project is riskier than another then it would make sense to use different discount rates because the market would value those differently.

Decision analysis, on the other hand, uses the perspective of a decisionmaker. And this can include much more varied and different types of risks than just an investor can consider.

And in decision analysis what you would do is apply an unadjusted discount rate, a risk-free rate, to many many different cash flow scenarios. And each of those cash flow scenarios have their own probabilities associated with them. So, in this manner you would take into account uncertainty in that regard.

Going now to some different views on discount rates, one of the people who've had a great deal of writing on this is Shimon Auerbach. And he's firming in the camp that you take a look at the particular expense in question and discount it according to its perceived risk.

So, in his view, a risky fuel expenses, such as natural gas, would be discounted using the market view of that risk. And since it's a cost, and since it's a risky cost, we would discount that at a much lower level than is typically being done.

In his view these are being discounted

at too high levels, and making them seem inexpensive in comparison to other costs. So these should then be discounted at lower rates in accordance with the capital market theory. And as I said, he's done a lot of writing on this.

And also I alluded to the Electric Power Research Institute also looked at this. They believe that the relevant cost of capital is specific to the project, not the corporation.

The problem from both Auerbach's and EPRI's point of view is that the weighted average cost of capital is the cost to the entire corporation, including both debt and equity, that's an average cost of capital to the corporation that may not be specifically applicable to any specific project in their portfolio, and it certainly may not be applicable to a proposed project that isn't in the portfolio at all.

Other views on discount rates. We have a response in the last IEPR, some comments that were posted, of C.K. Woo. He's firmly in the camp that uncertainty drives a portfolio's cost risk. And if you were to internalize all the uncertainties with different discount rates, the resulting portfolio, itself, would not have any variance whatsoever.

So he says that the presence of uncertainty dos not change the decisionmaker's use of a discount rate. And that's where we get into risk aversion.

If you have a couple of different expected costs, say you expect one cost has a probability of occurring 60 percent and another cost at 40 percent, it may have the same expected cost as a certain cost, say $100.

So if somebody told you you were going to receive $100 in the future and it was a sure thing, you would discount that at your own discount rate. But if they said that you had a higher cost, a higher percentage change of getting some higher amount, and a lower percentage chance of getting some lower amount that averaged out to the same $100, if you were risk neutral you wouldn't care because the expected value would be $100.

But, if for some reason you needed a certain amount of money or if a certain one of those values you didn't want to accept it, then you would not be risk neutral and you may or may not value that portfolio at the same amount as its expected value. Especially if one of those probabilities turned out to contain a negative amount.

So in that case what that's called is a certainty equivalent. So, in other words, how much would you take in a certain amount to forego the entire process and just accept that amount of money. So that's what's called certainty equivalence.

I may have gotten ahead of myself a little bit, but Woo says that risk adjusting discount rates defeats the purpose of portfolio analysis.

Stokey and Zeckhauser, some other writers, pretty much agree with that. And they say the correct analytical approach is to separate the question of risk-free discount rates from how we value risky outcomes. And that's what I was referring to when I mentioned certainty equivalence.

That's a very difficult thing to do, is to figure out how much something is worth to somebody as a certainty equivalent. But conceptually that's the way to go in the minds of a lot of people.

Other writers also point to some analytical difficulties with adjusting discount rates. Everett Schwab say that risk-adjusted rates are not a linear function of risk. They don't believe that there is a linear relationship between risk and discounting. They don't believe that variance and cash flows alone is an adequate measure of risk, which also depends on expected value.

Pearce and Turner, they say that risk does not seem to be related to time in such a way that the scale of risk obeys an exponential function, this is implied in the use of a single rate in the discount factor.

When you discount something you're using a certain percent per year over time. And so that basically is an exponential value. So they're not so sure that the value of money over time is exponential in how you value the tradeoff from one time period to the next.

Before I get into this slide, just for a second, we have seen that there's a lot of thinking that's been done on whether to adjust for discount rates for risk or not.

My view is that those people who caution against it, this caution seems to be based on the idea that there are more appropriate ways to include risk in our decisionmaking, rather than just adjusting the discount rate.

You may want to look at how you value risky outcomes through certain equivalents. You might want to look at the specific probabilities out there and identify those probabilities and what they apply to.

And another way to go is through focused policy analysis.

So nobody is saying not to -- excuse this use of the word discount, but not to overly discount future generations' interest, but not to actually do that through the use of discount rates.

So, as I said, the actual nuts and bolts of applying social discount rates to a stream of numbers is pretty simple. And what I will do here is now given an idea of how it actually applies using theoretical combined cycle power plant.

So what we have here is kind of two sets of columns. One is present value and one is levelized cost. Discounting is important to both present value and levelized calculations. And both calculations are important to look at.

Our own Energy Commission cost of generation model does use levelized costs. And what a levelized cost is, is a present value times another factor. Present value is where you're taking future cost streams, and present-worthing them, and adding them all up so you get a single sum.

So in other words if you had ten different costs occurring each year for the next ten years you present value all those, add them up and you get a present value factor.

Well, when you're looking at a power plant and trying to compare it to another type of power plant, you also have capital costs to consider. So, to allow us to add in the capital costs, which has been -- capital costs are spent over the past few years, for example. So, if we have a power plant in the ground that we've just constructed, we've had about five or six -- anywhere from two to five years of expenditures.

That does have a present value, but then also we want to see how that makes a difference to the people who are going to be paying for it in the future. So we have to spread that out sort of like a homeowner's mortgage, out to 20 or 30 years in the future. And the process of doing that is called levelizing.

So, levelizing does include another factor that's applied to the present value to spread that cost over time.

So what we have here is only changing the discount rates as it applies to the fuel costs only of a natural gas plant. So in the left-hand column we have the fuel price escalation rate, ranging from 1 to 6 percent per year. And for those of you who are used to looking at such things, 6 percent a year is getting up there pretty well. That's doubling fuel costs about every ten years or so.

So we're looking at a 5 percent discount rate and a 10.65 percent discount rate, both for the present value and the levelized cost.

These discount rates are pretty much comparable to the 3 and 7 percent real that we have been talking about, because they can be construed to include inflation. And the 5 percent discount rate would be about 3 percent less inflation. the 10.65 is actually pretty close to the California independent utility weighted average cost of capital. So it makes a convenient comparison.

So, looking at just the present value, the 5 percent, 10 percent discount rates, going across, let's choose 3 percent price escalation, for example. At 3 percent you have $1028 present value compared to 641 at the two different discount rates. That's a 60 percent difference.

If you go over to the levelized cost portion you see that, now these are going to be annual payments, there's only an 82 versus $78 difference, which is only 5 percent compared to the 60. That's because of the other factor I was talking about, called the capital recovery factor.

When you multiply a present value times capital recovery you get the levelized cost. The present value increase as the discount rate increases. The present value decreases as the discount rate increases.

But the capital recovery factor is different. The capital recovery factor increases as the discount rate increases, so it sort of tends to moderate this percentage difference a little bit. And that's why these numbers are different.

When I looked at them I was sort of startled at the differences. Again, I think everything depends on your perspective. Levelized costs is a very very popular measure to use. And therefore, I thought it important to include this. And, again, this is fuel costs only.

And if we compared the total costs of a combined cycle power plant we have additional columns in here, everything else is pretty much the same conceptually, this is what I was talking about. We have nonfuel costs, which are, in this instance, just the capital costs. So in the second column you can see the present value is going to be $349, whereas levelized it goes down to $42.87, which is again equivalent to a homeowner's mortgage. So then you add that into the fuel costs and you get slightly different percentage differences.

And in the last case, because the capital costs remain constant, therefore it tends to add further moderation to the differences. So that before you can see that the differences ranged between 55 and 69 and 2 and 10, the percentage difference column, now the percentage difference goes from 34 to 48. And then in the levelized, only from 1 to 7 percent difference.

Sort of another way to look at this, probably is even more confusing, but hopefully not. It shows that as you change input assumptions, and this is to show that the relative difference change in the discount rate -- everything else. So the black line with the squares is the discount rate.

So, going across on the bottom as you change the discount rate from zero percent to 10 percent higher, then 20 percent higher, to 30 percent higher, you can see, looking at the vertical axis, that the change in levelized cost doesn't matter too much.

If you look at fuel price, as an alternative example, if the fuel price, sort of starting in the middle of the graph, changes from zero to 50 percent that has a 40 percent change in the levelized cost.

So what this shows is fuel price is really important. The installed cost is pretty important. And the capacity factor is fairly important in the overall cost of electricity from a particular type of generating source, in this case combined cycle.

Again, there's different ways to look at this, or to look at things in general. If you key in on present worth then that becomes much more important; levelized costs becomes a little bit less so. And when you question the change in assumptions of many other different factors, then that shows you that those are, indeed, very important as well.

So, we see that there's a lot of different ways to look at this. The Energy Commission knew that this was going to be extremely important in long-term planning. And in the last IEPR made long-term planning a focus, and suggested that we would want to try to get the Public Utilities Commission to also look at this. And we've heard this morning that this is, indeed, in process.

So, to help us further understand where to go from here, I've included five questions, both in these slides and in the report that I prepared that is online. And we can discuss -- I'll go over these questions a little bit now, so I'm sure that we could entertain some response to these questions today. Also there will be an opportunity after the workshop to provide post-workshop comments. And we'd certainly welcome people's thoughts on these questions now or during the comments.

So to start off with the questions, if the utilities are required to meet an RPS standard, do we still need to talk about risk-adjusting discount rates for natural gas costs?

This question arises from my observation before that discount rates can be looked at either project-by-project, or in planning, overall planning. So, the question here is -- and I noted before, too, that discount rates, you might want to adjust discount rates to take into account market inefficiencies or externalities.

So, if, indeed, the RPS standard is based in part upon the perception that fuel costs were getting too high, and people deemed it appropriate to require the utilities to meet a certain standard, does that or does that not take the place of adjusting a discount rat for the same purpose.

So when you're evaluating portfolio costs would you also want to look at adjusting discount rates. If the RPS has been put in place to mitigate fuel costs. What if it's been implemented for reasons other than fuel costs. What if RPS is mostly for carbon risk. What does that mean.

If the RPS does not represent a binding constraint, in other words if the utilities can go as high as they wish, does that also have an implication on whether or not you would use fuel risk as a reason to adjust discount rates.

And I guess what I would do is just go through these, unless anybody has a comment as I'm going through, or we can come back to them individually.

If utility long-term procurement plans do use a very wide range of natural gas prices and uncertainties, would this take the place of using risk-adjusted discount rates, or would we still want to use those somehow.

What about when the long-term plan is done and you receive bids in response to an RFO. As I mentioned, it might be possible to use discount rates or it might be preferable to use risk-adjustment of discount rates when you're using project-by-project head-to-head comparisons.

So when you get project bids in, would

this be the appropriate time to use discount rates that have been adjusted for risk. If not, are there are other adjustments to risk that can or should be used.

One thing that I didn't talk about too much, when they talk about risk-adjusting cost streams, there's many different cost streams associated with the projects. There's not only fuel costs, there's future O&M costs, there's capital costs, there's other sorts of risks that are inherent in project development.

If we do determine that in some case that's desirable to use risk-adjusted discount rates for fuel costs, are there other types of risky costs that we should then consider using risk adjustment for. Or should we just keep it to fuel costs only.

And last, if it's appropriate for valuing natural gas costs, should the discount rate be based on a social discount rate or some other measure, or how should that rate be derived, whether it be social or anything else.

I believe that's it. So I'll turn this now over to Commissioner Byron and entertain any questions you might have at this time for me.

PRESIDING MEMBER BYRON: I don't have any specific questions. It's a lot of material here. I think I'd like to reiterate something that you said in your paper, as well, for the benefit of everyone, Mr. Ringer.

And that is that we identified in the 07 IEPR that we're going to make some development of a common portfolio analytical methodology a core focus of the 08 IEPR. And with the clear objective of influencing the long-term procurement plans filed by the IOUs with the CPUC in December of 08. And I just bring that to light, as well, so that everyone understands where we're getting with this.

I like your questions, and perhaps we'll have opportunity to get into some further discussion with some of the investor-owned utilities who are present here, as well, with regard to some of them.

But, again, I just wanted to reiterate the importance of this work with regard to where we're headed in the 08 IEPR and the recommendations we plan to make.

I'll turn to my fellow Commissioners. Any questions, Commissioners?

ASSOCIATE MEMBER PFANNENSTIEL: You know, the questions of -- Mike, and I appreciate your laying this out like this. I think it would be really more useful to get into the comments from the other parties. I think from the utilities and others who have different points of view, or maybe would reinforce what Mike is saying.

I think that would help to frame the questions that I think we need to get into.

PRESIDING MEMBER BYRON: Agreed. So, Ms. Korosec, how are we going to do that?

MS. KOROSEC: Well, given the time I would suggest that now's the time -- a good breaking point for lunch. We do have a presentation from Mr. Marcus of TURN that he wishes to do. And then we can get into the public comments after that.

So I would suggest we break and come back at 1:15.

PRESIDING MEMBER BYRON: Okay, let's do that. You know, I'm still upset that they haven't changed this clock back three minutes. So I'm going to say 1;10 by this clock, and that'll make us about 1:15.

Thank you all very much. We'll see you at 1:10 by the Energy Commission's clock.

(Whereupon, at 11:55 a.m., the workshop was adjourned, to reconvene at 1:15 p.m., this same day.

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AFTERNOON SESSION

1:16 p.m.

MS. KOROSEC: We'll start the afternoon here, and we're going to begin with a presentation by William Marcus from TURN on social discount rates.

PRESIDING MEMBER BYRON: Mr. Marcus, before you begin, go right ahead. I'm sorry about the ambiguity around the clocks. Mr. Tutt pointed out to me, we'll go by that one up there. I like the time on that one better.

MR. MARCUS: Good afternoon, Commissioners. I'm Bill Marcus. I represent The Utility Reform Network. We haven't been at the Energy Commission very long, so I'm going to go through -- I put up a couple of slides that I might not otherwise put up. I'll put up a witness qualification slide. Been around for 30 years; have done quite a bit of work; have been at the Energy Commission actually my first job in California.

And relevant to this particular assignment I actually, 35 years ago, thought an awful lot about this topic because I was trying to teach public policy students how to do it right.

We do have one prior presentation which we're asking you to incorporate into the record. We've got copies for folks, for the Commissioners and Advisors, and for the court reporter. I've also got a computerized copy available for staff, and put a few outside on the table. This is our testimony in the last Palo Verde-Devers case.

Turning to the substance, basically the argument that people have made in supporting the use of social discount rates in various purposes are that the private sector does not give adequate weight to the future relevant to the present when trying to take the public interest into account or looking at things like public goods.

And a second corollary that certainly was being taught 35 years ago when I was teaching it is that this argument is particularly important for irreversible impacts. You care more about the future when you're changing it in a way that can't be undone.

And the argument against the social discount rate are that it is less than the cost of capital in the private sector. Which means if you pick projects that only pencil against the social discount rate, you may crowd out other projects with higher benefits, other infrastructure or private sector projects with higher benefits. National income will be lower and society will be worse off.

Another thing I would add on this slide is there's an issue of transparency. Essentially you can get results that are driven by discount rates. And it's not clear how the discount rate or other assumptions affect it. I'd rather be a little more transparent rather than changing discount rates when doing this kind of analysis. And I'll give you a little bit of extremely bad poetry which was called, on the evaluation of water projects, from several years ago.

At 3 percent the case is clear; at 4 percent some doubts appear. At 5 percent it's losing strength; and at 6 percent it's certain death.

So, the choice of discount rates really does affect your choice between the past and the future.

When you look at the utility sector, we have a situation where the social discount rate is less than the cost of raising debt and equity capital either by a utility or possibly even more so by a private sector merchant firm building a project like a power plant or a transmission line.

It's also less than the rate of return that users of the utility system must pay when the utility builds something or when they're paying through a power purchase agreement for a private sector project.

This means that ratepayers are likely to prefer lower rates to building a project that barely passes the cost effectiveness test with a social discount rate.

And the effects can be fairly large. I mean I'll go back to table 2 on page 11 of Mr. Ringer's presentation. Not going to try to get you to turn the whole thing up, but I will tell you that even with 1 percent real escalation in fuel the cost of a combined cycle power plant is 34 percent higher net present value. The levelized cost isn't much different, but it's 34 percent higher net present value, with a 5 percent discount rate than with a 10.65 percent discount rate.

If you use the social discount rate that is telling you implicitly go out and spend 35 percent more on a nongas resource than on a gas resource. Now you may or may not want to do that, but you don't want your discount rate to drive a decision like that. You want to think about it carefully rather than sort of have getting backed into it by your discount rate.

Turning briefly to what you might actually want to use a social discount rate, it may be theoretically better for a case where a decision is irreversible. And this Commission has used something like a social discount rate for building and appliance standards.

And, you know, fairly hard money on discount rates, that's probably the best place to think about using it. Because you get lost opportunities in conservation if the standards don't look at the future.

But then when you're trying to look at sort of an ordinary project to build a power plant or a transmission line, it doesn't generally fit this definition. I mean I've come up with an example that there could be some irreversible effects of building a transmission line, but there are irreversible effects on environmental costs in this case.

You generally have the option to do a

project now or do it later. And that's the type of analysis that should be done in these types of plans that the Energy Commission is doing.

If a power plant turns out not to be economic, for example, if gas prices go up, you can make a decision to turn it off or run it quite a bit less. And there's an economic penalty for having built it if you run it less. But it isn't, you're not doing some creating a problem where it's physically impossible to change something, or it's economically prohibitive to change something, to change your mind.

I mean if you don't put that insulation in that wall on your building standards, you're never going to be able to go back and put more in there, because it's economically prohibitive. You know, most of your decisions in power planning are not like that.

Now we turn to the topic at hand, which is if you try to discount different elements with different discount rates. And the example that jumped into my head is what are you doing if you're trying to compare gas with nuclear power.

Gas has its own set of risks. Nuclear power, we don't know what it costs. I mean at the moment I've been seeing estimates of cost anywhere from $4000 to $8000 per kW for projects built in the mid-teens. And we also have other operational risks such as capacity factors in the future.

So, if you give gas a social discount rate and do the types of calculations we were just talking about, all of a sudden you can spend 39 percent more, or 34 percent more on that nuclear power plant.

But the nuclear power plant carries with it a whole set of its own risks, but they're all capital related and fairly early in the project life. They don't fit with the discount rate analogy.

If you put a higher discount rate on the nuclear power plant because it's risky, you end up actually making it look better. If you put a lower discount rate on the nuclear power plant to make it comparable to gas, the level of risk doesn't get borne out particularly well because most of the risks are going to be done by the time you finish building it in say ten years.

So, it creates a set of fairly difficult and thorny problems for the evaluator, which is why I come to my second point. Which is run scenarios to cover relevant risks. And I think your staff in the first presentation this morning has shown that that's really what the next IEPR is going to be about. And I think it's a good thing to sort of start looking at scenarios, start looking at the strengths and weaknesses of particular projects or plans or portfolios under different futures.

I also think the policymakers are smart enough that they're not going to get tangled up in the iron wall of the written number on computer paper so it must be right, and can pick a plan or a project that may be more expensive than the least-cost under the expected scenario if it has other attributes that are valuable. Such as saving money if the cost of gas goes up or certain environmental attributes that you're looking for, such as saving money if the cost of carbon offsets goes up.

This next slide takes that into account a little further and says if you're looking at strategic benefits try to put as many values on things as you can. You know, economists like numbers, and you know, it's one of those things where we have the law of professional technology.

If all you've got is a hammer, everything out there starts looking like a nail.

So I would suggest you try to put values on strategic benefits rather than using the discount rate as a shortcut to analyze them. And when you do that you'll find that some can be calculated directly; they may be a little uncertain such as air emissions values, but you can take a run and calculate those.

Some of them are already internalized. I mean we have legislation, we have an RPS and we have legislation that says specifically build transmission to make that RPS happen and make it work.

Some of them may be small when you look at the incremental value. We were talking about insurance as a benefit of transmission. And, you know, there may be an insurance benefit, but it's going to be incremental to a number of things that we've already done, such as 15 to 17 percent reserve margins, demand response equal to 5 percent of demand, long-term contracting a year in advance for 90 percent of your power, and utility-owned generation provided on a cost-of-service basis, which is a natural hedge.

So, there may be an insurance value to building a transmission line to avoid market power, but it's a small number.

And then finally, some of these benefits or costs may be extremely uncertain over long periods of time. If you look out 30 or 40 years to try to figure out what's going on with gas prices, or even more, something like the market power mitigation of transmission, the whole technological structure of the industry could change at 30 or 40 years.

So, some of the numbers that we're thinking of as risky may be not just risky, but uncertain in all sorts of directions that none of us have quantified.

If you do use a social discount rate, make sure to do some sensitivity work at a utility cost of capital so people can understand the effects of the discount rate and what it's doing to the analysis.

Second option -- this was developed by a fellow named Dr. Stephen Marglin at Harvard in the late 1960s -- is if you're using a social discount rate, require the benefits to exceed the cost by a significant amount. That way you can give more weight to the future without crowding out as many investments in the present that might be minimally cost effective using a social discount rate.

You also, in this type of analysis, want to look at paybacks. I mean I'll tell you, from looking at some of the advanced metering infrastructure cases of the utilities, that both Edison's and San Diego's, on a net present value basis using the utility discount rate, paid off about 30 years from now and had benefit/cost ratios of less than 1.1. Which the folks at TURN found a little bit problematic. And this is with all utility assumptions, not assumptions we were using.

A quick slide on there may be an unintended consequence out here if the social discount rate starts getting pushed pretty hard. And that is if you start using the social discount rate for gas, you're going to not only get more energy efficiency cost effective, but you're going to make the existing energy efficiency more cost effective.

And under the CPUC's current incentive framework for energy efficiency utilities get a percentage of net benefits. The net benefits go up; we end up paying more per unit of conservation, even for the same amount of conservation. And, you know, we're concerned that if people are not very careful with this, we could end up with what TURN believes are utility incentives for energy efficiency that are too high, that end up being even higher, which I call it money for nothing on this slide. So you've got to be careful when integrating this between the two Commissions.

So, in conclusion, we would recommend that you do not use social discount rates when evaluating generation and transmission projects or evaluating natural gas because ratepayers have to pay 9 percent to use capital on a nominal basis, 6 or 7 percent real, they also have to pay income taxes and property taxes, which takes that cost of capital close to 13 percent.

We like the scenario analysis that staff has put forward better than trying to change the discount rates to look at risk. And we just put a couple comments on what the Commission's decision was in Palo Verde-Devers 2 and what the Office of Management and Budget had said that are both consistent with a couple comments on the staff presentation.

And with that, I thank you, and we'll take some questions if people wish to ask them now or later.

PRESIDING MEMBER BYRON: Go ahead.

ASSOCIATE MEMBER PFANNENSTIEL: I just want to make sure I understand. So you're obviously recommending that we don't adopt the social discount rate as being too low and having the consequences you described.

And I'm also getting the impression that you really wouldn't rely much on discount rates, high, low or otherwise. That there are a lot of other ways of evaluating projects that you would advise us to think about.

And so the discount rates are just bookends in a scenario, or are they irrelevant for policy deliberation anyway. How would you have us think about them?

MR. MARCUS: I think you have to use a discount rate of some sort, or maybe even more than one of them if you choose to do that, to compare the present and the future.

You can't avoid using it. But it's basically a tool rather than, you know, rather than -- you know, the determinative decision when making energy policy is policy. It's understanding what the numbers are on the page. And I would prefer it if the numbers were with a discount rate of 6 or 7 percent real.

But it's understanding the numbers on the page, and recognizing that sometimes there are considerations, both having to do with insurance and having to do with the environment, which might cause you to deviate from, you know, just going strictly by the book to the least-cost set of projects.

ASSOCIATE MEMBER PFANNENSTIEL: I don't disagree with that at all, of course. It clearly is just a tool. But we're really here on the asking the question of whether -- and maybe the question isn't is a social discount rate a correct one, but rather is the existing utility discount rate that they're using their cost of capital, in that sense, is that too high.

And, you know, I guess I didn't hear much guidance from you on that. You don't agree that we should use something as low as a social discount rate, and yet where do -- do you think that the utility cost of capital as a discount rate is, in fact, the correct one for us to use in these circumstances?

MR. MARCUS: I would say for most purposes it is a reasonable discount rate to use for projects that are being bought and paid for by utility ratepayers. Is what I would say.

I'd say I think it's reasonable. I've seen some arguments for some higher numbers; I've seen some arguments for some lower numbers. But I know PG&E uses a variant that has an after-tax bond rate that I've basically had arguments with PG&E at the PUC about, that have been quite inconclusive. Because both of us have won and both of us have lost in different cases.

Edison uses a discount rate that's actually higher than its current rate of return because it says it really needs 12.75 percent return on equity for new capital. I don't happen to agree with that, either. That's too high.

But, you know, given that ratepayers are paying these costs, I think that a discount rate that's roughly proportional to the cost that they end up paying is probably the best thing you could do.

Now, it could be a lower discount rate

if the Public Utilities Commission would adopt my recommendations and give the utilities a rate of return that was single digits rather than starting with 11.something percent. I wouldn't object to the lower discount rate under those conditions.

I think the utility cost of capital is a good metric because it's tied to what ratepayers are paying.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

PRESIDING MEMBER BYRON: Well, thank you very much.

MS. KOROSEC: All right, Commissioners, shall we go ahead and move to the public comment period? I believe you do have some blue cards in front of you.

PRESIDING MEMBER BYRON: Yes. So, we'll start with those, thank you, Ms. Korosec.

I'm taking them in the order that I was provided them. Do we still have Mr. Lutz on the phone?

(Pause.)

PRESIDING MEMBER BYRON: Reconnected? Disconnected, thank you. I also have a card from looks like Marsten Schultz from Clean Power on the phone.

(Pause.)

MS. SPEAKER: Apparently he also disconnected.

PRESIDING MEMBER BYRON: They don't have our clock, I guess, access to our clock.

Fong Wan, VP Energy Procurement, PG&E.

MR. WAN: Good afternoon. My name is Fong Wan. I oversee the energy procurement function at PG&E. I'd like to share a few of our thoughts, as well as clarify some of the questions that was asked earlier today.

The first is that under the California Public Utilities Commission we have two separate processes. One is for the long-term plan and the other one is for the request for offers in which we enter into commercial transactions. They take place in sequence with the long-term plan first.

That is where the utilities are granted with the authority to procure X amount of megawatts for new generation.

In terms of the long-term plan, it is indeed a very challenging process. What we're talking about is coming up with a demand side, as well as resource side.

In terms of the demand side we have our typical challenges of load forecasting, especially with the peak load forecast. As you may recall in the summer of 2006 we had some very hot weather; even the summer of 2007 around Labor Day we had some very unusual weather. And as well as this past June we had some very unusual weather.

So we believe we're into uncharted territories in terms of peak load forecast in which none of us really have a good handle on if we're to look at historical information.

But a even bigger challenge has to do on the load side is who should the utilities plan for. Right now in PG&E's service territory since the recovery of the energy crisis there's only been one merchant plant built, that's the Calpine Metcalf power plant, without the utility's involvement.

And while there's a lot of discussions about reopening of DA, as well as community choice aggregation, it remains to be seen who will plan for those two groups of customers.

At the present time the CPUC has asked the utilities to assume the planning responsibility similar to the old days for all customers. And if any customers were to depart from PG&E, they would pay -- the departing customers would pay for their share of the above market costs if there is any associated with the new generation.

In terms of the resources this is also quite challenging because the CE, demand response, renewables, distributed generation are really assumptions for the utilities within this proceeding. They're really not litigated within this proceeding. They have their own proceedings.

But the inputs and assumptions to come up with the resources are extremely important. Because what happens is that the new generation, the new needs fall out as a result of the assumptions for CE, DR, DG and renewables.

In addition, the retired generation aspect is also critical assumption. The PUC decided to adopt an assumption of 600 megawatts of retirement for each and every year until all the old plants are retired. So as a result we end up with a number such as 800 to 1200 megawatts.

So a lot of assumptions go in there. It is done without the involvement of the PRG. It is something that PG&E submit on its own. And there are certain information that is confidential, as discussed earlier. In general, there are plans that are confidential such as utility's nuclear fuel plant. How we plan to procure nuclear fuel and how we plan to hopefully, one day, dispose of it.

As well as the gas hedging plan. Gas hedging plan is a hedging activity we do with Wall Street firms for several years out, three to five years. And this is where we clearly lay out at what strike prices will we do our swaps, we do our options. What time of the year. And what amounts. So these are quite confidential.

And in terms of the prices, we actually are only asking for protection on the first three-year prices, as well as our net open position on what time of the year, what hours or months will we be purchasing.

So, in general, it's whatever is commercially confidential will we ask for protection.

We also talked a little bit about the PRG. I would respectfully ask that the CEC reconsider its decision to allow staff to participate in the PRG. And from PG&E's

perspective, it's been a very successful process. It's involved many parties, DRA, Energy Division, TURN and many. It is nonbinding to any of the participants. They simply get the information from inside on the decisionmaking process.

And they also see tools that each of the utilities use. They get an opportunity to compare across utilities as another way to keep the utilities honest with each other. As well as the assumptions that we use. We also provide lots of analysis to the PRG based on the PRG's request. The PRG also has the benefit of independent evaluator who can separately and in parallel run analysis next to PG&E, as well as the other utilities.

At the end of the day, PG&E takes into consideration all the input from the PRG members, but we make our decision. And all the PRG members are free to challenge any of the decisions we do make at the Public Utilities Commission.

We consider that to be very successful process. For example, in the last long-term RFO we held a total of 18 meetings. Some of those meetings ran as long as half a day or even a full day. We will take as long as necessary to make sure everyone understand how we came down with our selection process.

In terms of the evaluation criteria that was discussed earlier, PG&E uses a number of criterias. These are liability, which is a developer's liability, whether the developer has had any track record of developing power plants in California. Or if the developer has a permit from the CEC. Also economics.

By the way, we do -- that gentleman left -- we do use the utility weighted average cost of capital for discounting. We also consider transmission status, the technology, itself; environmental justice issues, as well as portfolio fit.

And what we do is we receive 57 offers; we ended up selecting seven. We go through a process of evaluating each of the six or seven categories I said earlier. What we show to the PRG is projects in three colors: Red, yellow or green. Green being the ones that we would like to proceed with, and the red the ones we would like to eliminate.

Most of the projects are pretty obvious if they fall into the green or the red side. We spend most of our time debating how to turn the yellow into either green or red. And we go through a process without an exact weighting for each of the portfolio components I mentioned earlier. It's very subjective. We discuss them over and over until everyone's comfortable with that process.

Looking back at our process we did do some things not as well as we should have. And I think the number one is probably under-estimating the impact of having plants permitted. Even if plants have not been permitted -- have been permitted, I'm sorry, they also face additional challenges from local governments or local issues. And I think that is one criteria that we will take a lot more seriously with more weighting, going forward, on the permitting of the power plants.

And that's all I have, thank you for your time.

PRESIDING MEMBER BYRON: Go right ahead.

ASSOCIATE MEMBER PFANNENSTIEL: Fong, just a couple questions. One just gets back to the point you just made. Even after a plant has an Energy Commission license, it faces other challenges from local authorities. Such as what?

MR. WAN: I can give you one example, that's Calpine's Russell City. It's my understanding that was permitted by the CEC several years ago. And today we are still working on an amended contract to extend their online date. They have faced the challenges by -- I can get you the information later, but --

ASSOCIATE MEMBER PFANNENSTIEL: Yeah, I don't want to talk about a plant that's --

MR. WAN: They could not get their financing due to a few lawsuits.

ASSOCIATE MEMBER PFANNENSTIEL: Okay. Because the point is that the Energy Commission does have authority to, has unique authority for licensing plants, right. So, we can --

MR. WAN: Absolutely.

ASSOCIATE MEMBER PFANNENSTIEL: -- if there's a local problem, it really is the Energy Commission's authority that can, if we need to, can trump the local authority, correct?

MR. WAN: That's my understanding.

ASSOCIATE MEMBER PFANNENSTIEL: Okay. But then earlier you said something about there's only one merchant plant built without utility assistance. Now what we, of course, hear from the merchant plant is that the reason they're not getting built is that, even though they have an Energy Commission license, is that they can't get a utility long-term contract.

And we hear that over and over, for the 9000 megawatts that we have licensed and haven't been built. That is the most common reason given to us when we go back and ask.

So somehow in your procurement process these 9000 megawatts are not getting selected. And so I don't know, and I think that we at the Energy Commission have not, because we're not privy to a lot of the information, have known whether this is a flaw in the procurement process, whether we're licensing plants that are fatally flawed when they then get into the utility process, or how that comes about.

But we're hearing that there is some resistance from the utilities in terms of selecting these plants.

MR. WAN: Sure, I can cover that, Commissioner Pfannenstiel. Out of the seven contracts that we selected last RFO, five of those were for power purchase agreements, and two of those were for utility ownership.

And out of those seven contracts -- I thought this may be a question, so I have a list of the 9000 megawatts from the CEC's website here. Russell City was selected; it is on that list. And we did not select Calpine's San Joaquin or East Altamont plants, because those two are also owned by Calpine. The PRG made its decision and we agree with that, that we should not be buying all of our RFO outputs from one company in terms of competitive. So those are the three plants in northern California.

Then there is also Colusa Generating plant that's also on the 9000 megawatts. That was included as a winner in our RFO. And also listed up here is San Francisco Reliability project. That one has its own course, as you may know.

Other than that -- oh, there's Tesla. Tesla's another 1000 megawatt. And we have submitted a proposal on Tesla to backstop for the fail plans.

So if I missed any of the northern California sites, I will be happy to discuss this with CEC Staff. I believe they actually took in consideration at one time or another every single one of those projects.

We believe that we were quite open to the IPP industry, having selected five of their contracts. The challenges that we're facing is not one that we envisioned. One is it's hard to get power plants through the permitting stage if they're not permitted, or they face other obstacles.

The second is that the entire procurement process in which the PG&E will run its RFO and then have about eight months for the PUC's approval, and then the merchant generators will go on to build the plants, including transmission issues, requires them to lock in fixed prices in the order of four to five years.

And we are facing very high pricing increases in the basic commodities, whether it's steel, concrete, or skilled labor. That has really put a tremendous hardship on the IPP industry. That's one of the reasons given to us, Commissioner Pfannenstiel.

ASSOCIATE MEMBER PFANNENSTIEL: And so is PG&E going back, then, into the power plant construction business?

MR. WAN: PG&E, the policy we put in front of the PUC is that we believe and support hybrid market structure. That we believe the proper balance for utility generation, new generation, is approximately 50 percent.

ASSOCIATE MEMBER PFANNENSTIEL: Fifty, 5-0 percent?

MR. WAN: 5-0, five-zero.

ASSOCIATE MEMBER PFANNENSTIEL: Utility --

MR. WAN: That's correct.

ASSOCIATE MEMBER PFANNENSTIEL: -- built generation?

MR. WAN: That was not --

ASSOCIATE MEMBER PFANNENSTIEL: What was the last power plant that PG&E built in California?

MR. WAN: Gas-fired power plant, I believe, was 1973, Pittsburg 7.

PRESIDING MEMBER BYRON: I believe the Humboldt plant was the first time in 25 years that we've seen a PG&E application before the Commission.

ASSOCIATE MEMBER PFANNENSTIEL: Utility. And so it's really getting a whole new business line within the utility business, then?

MR. WAN: That's correct.

ASSOCIATE MEMBER PFANNENSTIEL: And that decision was made, can you just give me a sense of when and why?

MR. WAN: Well, the first one was very opportunistic. That has to do with what we call the Gateway Power Plant. It's formerly owned by Mirant. It was called Contra Costa 8. And I appeared before this Commission on the assignment of a permit.

And PG&E received that permit along with a site as a settlement for Mirant's alleged actions during the energy crisis.

ASSOCIATE MEMBER PFANNENSTIEL: Rather than getting into the specific plants, but why did PG&E and when did PG&E make the overall decision to go back into power plant construction; and why 50 percent?

MR. WAN: Sorry, I misunderstood the question. We made the decision when we filed the 2004 long-term plan; what was when we submitted our public position of 50 percent. And we believe that a balance of merchant generators, as well as utility generation, is in the best interest of the customers.

And we learned our lessons from the

energy crisis when PG&E lost its credit rating. Every single one of our PPAs, except for the QFs, took the credit provision out and terminated the contracts. That left us further exposed to the spot market, and escalating high prices into a very rapid spiral of running out of cash.

That was our number one concern.

I would like to --

ASSOCIATE MEMBER PFANNENSTIEL: So it was not a cost, it was a reliability question?

MR. WAN: From a reliability perspective. But in terms of the costs, each of our selections also have to line up with all the PPAs. We will only select a utility ownership opportunity if it is superior in cost or economics --

ASSOCIATE MEMBER PFANNENSTIEL: That, of course, though, is invisible to us because we don't see those costs, so we need to end up taking your word for that.

MR. WAN: That's probably true, but I would like to think that the Energy Division and DRA and TURN are also part of the process. And TURN has a pretty keen eye in looking out for the customers.

ASSOCIATE MEMBER PFANNENSTIEL: Right, but that's an advisory process, right? That's not a decisionmaking --

MR. WAN: It is advisory process, but they can challenge our selection if they do not believe those were in the best interest of the customers in the proceeding.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you; that's all my questions.

PRESIDING MEMBER BYRON: Mr. Wan, thank you for being here. I had a couple questions, as well. In fact, I think I might rephrase one of the ones that the Chairman asked earlier.

I just jotted these down. I heard a new criteria I hadn't heard before. I mean, I don't know if it's a published one, or as you say, it may have just come out of the procurement review groups. Too many proposals -- don't accept too many proposals from a single company.

MR. WAN: That was a concentration risk proposal, yes, it was.

PRESIDING MEMBER BYRON: Um-hum. And what's the concern there? That they might exert market power?

MR. WAN: Oh, the concern there is

actually very straightforward, Commissioner Byron. The concern is that the way all the market participants negotiate is, it's just like the way you expect when anybody who is for-profit is, they would like to squeeze out a little more pricing, a little more term advantages down to the end. And see how far they can test it.

And if we only have one company to negotiate, when we were looking for 2000 megawatts, and both of those two proposals came from one company, it's quite difficult to negotiate under those circumstances.

As well as Calpine was heading into bankruptcy at that time. It led to very unsteady situation to put all of our megawatts with a bankrupt entity.

PRESIDING MEMBER BYRON: Okay. There's another criteria that I'm aware of, and that's the new construction one. That we want to see -- you want to see respondents come back with new construction, no existing power plants, correct?

MR. WAN: That's correct. That's actually not a new criteria. That was very --

PRESIDING MEMBER BYRON: No, I didn't mean to say it was a new one. That's another criterion.

MR. WAN: Yes, it's been there since the 2004 long-term plan decision, and our RFO results, as well as the 2006 long-term plan decision. We are looking for new power plants under the PUC decision to replace the aging, inefficient and perhaps polluting older plants.

PRESIDING MEMBER BYRON: So, but at the time that criteria was put in place in 04, I believe there was a power plant that had just been built that then could not participate even though they did not have a contract for sale of power.

MR. WAN: That's correct.

PRESIDING MEMBER BYRON: So that excluded them from the process?

MR. WAN: That's correct.

PRESIDING MEMBER BYRON: For what reason?

MR. WAN: The reason is that the PUC decision was specific to ask for bring in new steel, new power plant to the marketplace. That power plant Calpine clearly said did not need a utility contract to be built. They said publicly they were going to go ahead and build it; therefore, it didn't need a contract to make it happen. That was our logic. And the Commission agreed with that.

PRESIDING MEMBER BYRON: Okay. With regard to long-term procurement plans, are there any penalties if you don't meet your plan? Is there any down side to not fulfilling your obligations on your long-term procurement plan besides the lights going out. We're talking about with the Commission.

MR. WAN: I should -- it's an excellent question. I think I should phrase, just give you a little picture of how we enter these contracts.

We actually want people to perform, so we ask for credit assurances in terms of LCs. And typically they give us a little bit of good faith money at the time we short-list them because we want to make sure legitimate. And the LC requirements step up when the PUC approves the contract. Then they continue to step up when more and more milestones are met.

And so that's --

PRESIDING MEMBER BYRON: Or they drop out of the process if they're not met.

MR. WAN: That's correct. And we give them their money back. We've never, so far, kept anybody's good faith money.

What happens is they run into hardship, whether it's on the permitting front or the lawsuit front, or even the economic front. All companies make a decision, am I better off going ahead and building the power plants into negative economics. or should I just walk away from a few million dollars of LCs. And some have chosen to do so, to walk away from their LCs.

And your question as to what are the implications for PG&E. Technically speaking, there isn't any implication besides the lack of reliability which hurts all of our customers. But we take that responsibility pretty seriously. And we would submit emergency measures to make sure the lights do not, to the best of our capabilities, do not go out.

In addition to that, we would probably seek some sort of medium-term contract with an existing power plant, whether it's been mothballed or still in place, to get at least started again. That would be our plan of actions.

PRESIDING MEMBER BYRON: So you take into consideration contract failure during the procurement process? In other words, do you go out and over-procure sufficiently to cover the possibility that one or more or many could fail for any one of a number of reasons?

MR. WAN: We did put that proposal forward, and the PUC did not adopt that type of proposal. In general, we said -- this is the best of my recollection, it's about a 25 percent possible failure rate. That was not adopted.

PRESIDING MEMBER BYRON: This is a little bit off topic, but just having you is too good of an opportunity to ask, I've always been a little bit confused about the pass-through costs of natural gas.

Obviously, you'd mentioned earlier this company interest in being 50 percent hybrid market. Let's assume that a majority of these plants, at least for now, are natural gas. You essentially get the opportunity to pass through those rising gas prices to consumers, correct?

MR. WAN: That's correct.

PRESIDING MEMBER BYRON: Through rate increases. And we have some pending right now, I believe?

MR. WAN: We do have some pending. They go through what's commonly known as a fuel adjustment clause.

PRESIDING MEMBER BYRON: Correct. So my sense is that you're not entering in the tolling agreements for natural gas on your current procurement, you're assuming that bidders on your RFO process are providing you fixed price energy costs, correct?

MR. WAN: Let me try to answer that to see if I understood it correctly. We are actually entering into tolling agreements with the power plants owners. So it's simply for the right to bring natural gas and process natural gas --

PRESIDING MEMBER BYRON: Okay.

MR. WAN: -- and to convert electricity. Separately we buy the commodity of natural gas from the companies such as BP and Chevron. And most of those transactions are indexed to either California border or to PG&E's citygate. And they fluctuate each day.

And then we go to hedge the index prices independently of the physical commodity with the Wall Street firms, and that's what I referred to as the fuel hedging plan.

PRESIDING MEMBER BYRON: Okay, so it really, to consumers then the price doesn't matter if it's procured power or if it's a utility-owned?

MR. WAN: That's correct.

PRESIDING MEMBER BYRON: Back to the issue of environmental considerations, and your admission earlier about some of the procurement that you've recently done and how difficult -- some of the difficulties we've had with them on the permitting side.

Without, again, we don't need to go into specifics, I don't think, but environmental considerations, to my understanding, have not really been part of the initial procurement. Are you indicating that that may be part going forward?

MR. WAN: I would --

PRESIDING MEMBER BYRON: And that's why you want the Energy Commission back involved in your PRGs?

MR. WAN: Well, I would like to do a better job than what we did last time. And that is one of the areas where my colleague, Mark Krausse, is going to be helping us to take the lead to make sure we understand all the stakeholders' needs better. Get out there, use our field folks to see what the local folks need and where environmentalists saying, if there are any airport issues or bird issues.

We need to approach the PPAs as if it's a utility-owned project. As former Commissioner Geesman used to tell me, he said, we are viewed as the enabler of these power plants, so you might as well understand we're going to take that approach as we go forward.

PRESIDING MEMBER BYRON: Um-hum. In fact, didn't I just read last week PG&E made some major decision -- I'm sorry, major announcements with regard to new renewables, is that correct?

MR. WAN: That's correct.

PRESIDING MEMBER BYRON: Would you mind telling this Commission about those?

MR. WAN: Sure. We made an announcement, along with two firms. One firm is called OptiSolar; the other firm is called SunPower. It was a total of 800 megawatts of photovoltaic renewable energy.

OptiSolar is 550 megawatts. It uses a technology called thin film. Basically the thickness of the silicon is less than our hair. And their drive is to crush the cost, making it as cost effective as possible.

SunPower's technology is a proprietary, highly efficient, traditional panel. But they put all the electrical contacts on the back of the panel so the front of the panel will have as much exposure to the sun as possible.

And you may have also heard that SunPower has a fairly innovative tracking capability. That means it follows the course of the sun throughout the day. And in all SunPower strategies to get the most efficiency rather than driving down the costs.

We selected these two companies because we thought they have good management. They are ready for the utility-scale. Both of them have projects in the tens of megawatts, whether it's in the United States, Canada or in Europe. We believe they are ready to scale into the hundreds of megawatts. We're pretty excited to see if that can work.

PRESIDING MEMBER BYRON: But I'm sure the number one reason you picked them is because they beat the market price referent.

MR. WAN: They came darn close.

PRESIDING MEMBER BYRON: All right, well, that's good.

MR. WAN: They came close enough for us to give them a shot.

PRESIDING MEMBER BYRON: The reason I bring these two up is they're the ones that I had in mind when I mentioned earlier that these are nonthermal. They will not be going through this agency for permitting and siting.

And we take heed occasionally for our process. But I think my experience with this Commission for the last two years is they do an excellent job of addressing all the environmental quality issues that need to be addressed in the siting of power plants.

These are big PV plants. These are the holy grail of the renewable industry. And I'm just concerned whether or not they'll get permitted through local agencies. I believe they're in the San Luis Obispo County area.

MR. WAN: That's correct. Both of them are, as well as a third project that we have already signed with a company called Ausra. They're all in the same county.

PRESIDING MEMBER BYRON: Correct. But that's thermal and that will be -- that's going through our process. So you're taking that into consideration, the selection of these two renewable projects?

MR. WAN: We actually did. The amounts of megawatts I mentioned, too, will be the full contract quantity. Both of the contracts were pretty complex in terms of phasing it out. The beauty of PV is that you can build them as small as 10 or even 25 megawatts. And it has plenty of flexibility to accommodate potential compromises.

PRESIDING MEMBER BYRON: Okay. Just one more question. I think it's a clarification. You may know, Mr. Wan, we had a workshop here last month on the procurement review groups. I found it to be very educational.

And every single panel member said the same thing you did, that they would like our staff back involved in the PRG process.

But I note, based upon that workshop and other subsequent meetings, that at this point besides the PUC and TURN, I don't think there's much other participation in many of the PRGs.

MR. WAN: We have our union --

PRESIDING MEMBER BYRON: There's been a long list of folks --

MR. WAN: Yeah.

PRESIDING MEMBER BYRON: -- that have participated in the past. But I think we're seeing essentially that's the membership that remains.

MR. WAN: I'm not aware of that. Can I get back to you on that?

PRESIDING MEMBER BYRON: Sure.

MR. WAN: I'll have to check it. Thanks.

PRESIDING MEMBER BYRON: Any other questions?

ASSOCIATE MEMBER PFANNENSTIEL: Let me just, on that last point, I think that would be excellent information for us to have in this proceeding. So if you could put something in writing --

MR. WAN: Sure.

ASSOCIATE MEMBER PFANNENSTIEL: -- for the proceeding, we'd appreciate that.

MR. WAN: Sure. What we can do is provide you perhaps an attendance sheet for the last several PRG meetings. Would that be sufficient?

ASSOCIATE MEMBER PFANNENSTIEL: Or just some other way of determining, you know, whatever you consider to be the membership of the groups.

MR. WAN: Sure.

ASSOCIATE MEMBER PFANNENSTIEL: Thanks.

PRESIDING MEMBER BYRON: Yes, but now having said that, I also have heard that TURN has made major contributions to this group. So I didn't mean to in any way diminish their input. I've heard very good things.

MR. WAN: Absolutely. I would also say so did the CEC Staff; the CEC Staff is part of the group.

PRESIDING MEMBER BYRON: We love them, too.

Thank you, Mr. Wan.

COMMISSIONER DOUGLAS: Could I ask one followup question on the --

PRESIDING MEMBER BYRON: Oh, yes, please.

COMMISSIONER DOUGLAS: -- siting process? If a power plant hasn't gotten its permits yet, and in the process of going through the permits, either through here or through the local agencies, and there are additional environmental mitigation, does that require a contract negotiation? Or do they have to start over in the RFO process? How is that factored in?

MR. WAN: We're in the process of tackling that challenge right now, because we've just started our current RFO.

In the past the developers were willing to assume the risk under the contract structure I mentioned earlier, which is post a little credit, and take the risk of assuming that could be successful.

So, it's assumed by the seller.

COMMISSIONER DOUGLAS: Thank you.

PRESIDING MEMBER BYRON: Thank you.

ASSOCIATE MEMBER PFANNENSTIEL: Thank you.

MR. WAN: Thank you.

PRESIDING MEMBER BYRON: I have one more card. Of course, I'll make sure it's open to anyone else that wishes to speak. Carl Silsbee here from Southern California Edison.

MR. SILSBEE: Thank you, Commissioners. I'd like to talk today --

PRESIDING MEMBER BYRON: Carl, please, tell us what you do at Southern California Edison.

MR. SILSBEE: I'm a Manager in our Resource Planning area. As such I'm responsible for both the LTPP proceeding at the PUC and the IEPR at the CEC.

PRESIDING MEMBER BYRON: Great. Thank you for being here.

MR. SILSBEE: I'd like to talk specifically on the social discount rate issue that Mike Ringer talked about earlier this morning.

I appreciate his thorough review of the literature and also I thought it was a fairly neutral discussion of the topic, which often attracts a lot of interest and advocacy.

One of our primary regulatory uses of discount rates is to evaluate investment decisions that are made on behalf of our ratepayers. That's the issue that we face in long-term procurement planning very squarely, is what do we do now, given an uncertain future.

In these applications what we believe is appropriate is to use a ratepayer discount rate because we're making decisions on behalf of the ratepayers. And we believe a rate of about 7 percent real is an appropriate reflection of a ratepayer discount rate.

We typically use our incremental cost of capital as a discount rate. And we use it not because the corporate discount rate is appropriate, but because we believe it's an appropriate proxy for our ratepayer discount rate. And that value is also consistent with private sector opportunity cost of capital.

When you sort through some of the different arguments pro and con with regard to discount rate in the material that Mr. Ringer put together, I think that the most relevant literature does support what we're doing.

If I can quote a specific piece of this on page 3, and this is a paraphrase of the federal, the White House Office of Management and Budget guidance on discount rates.

"The 7 percent rate approximates the opportunity cost of capital and is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."

A further benefit that we see of using a value of around 7 percent, and one that's based on our incremental cost of capital is it creates an alignment between the economic basis for decisions that we're making and what we charge to our customers to recover the cost of those investments.

There's a semantic issue here that I want to alert everyone to, which is the term social discount rate is subject to a variety of different interpretations. But one interpretation of it is a risk-free rate. And to the extent that there's a proposal to use a risk-free rate, I don't think that is appropriate for investments, because they're inherently risky. And we really need to incorporate that risk in our economic evaluations.

Thank you.

ASSOCIATE MEMBER PFANNENSTIEL: Excuse me, I just want to clarify what you just finished with. The risk-free rate in your point is that these investments are, in fact, inherently risky. Certainly gas purchases over some period of time.

Yet, the other side of that is that to the utility, certainly to the utility's shareholders, there is no risk. Correct?

MR. SILSBEE: That's why I don't believe a corporate rate of return or corporate cost of capital to necessarily be looked upon as the right economic basis. It's our ratepayers who bear the consequences of our reasonable decisions.

And we use our incremental cost of capital, which is very comparable to the private return, opportunity cost of capital, as an appropriate measure, we believe.

ASSOCIATE MEMBER PFANNENSTIEL: Thanks. Got it.

PRESIDING MEMBER BYRON: Thank you very much for being here. I guess, and I can go through the same litany of questions that I asked Mr. Wan from PG&E, as well, but I won't. I'll ask you a simpler one. Is there anything that you'd like to add with regard to some of those topics that we discussed earlier with Mr. Wan?

MR. SILSBEE: Well, Edison also supports having the CEC return to the PRG proceedings. I think one of my colleagues, Mr. Cushnie, appeared in the workshop that you held some time ago, and took that position.

The PRG is not a decisional body in our view; it's a body or sounding board for discussions and informal communication among parties. I think it has built a much higher level of trust of what the utility staff are doing with regard to procurement.

And I think it's built trust among the utility staff as to the motives and the knowledge and capability of some of the intervenor groups. And I think it's that frank exchange of ideas in a private setting that is the value of the PRG process.

PRESIDING MEMBER BYRON: And we tend to like frank exchanges of ideas in public settings. We think the public's better served. And that's really the reason that we're not participating in those confidential meetings.

MR. SILSBEE: I appreciate that. The problem that we face is many of the issues that we confront in PRGs are things that cannot be shared with market participants. And that's where we wish to draw the line. We don't wish to draw the line to prevent decisionmakers, agency staff or consumer representatives from knowing our inner thinking about pricing, quantities, strategies --

PRESIDING MEMBER BYRON: Right. But that's part of the dilemma, isn't it, Mr. Silsbee, is having --

MR. SILSBEE: That's exactly it.

PRESIDING MEMBER BYRON: -- the biggest market participant in the room. Is Southern

California Edison pursuing a similar strategy as PG&E in terms of a 50 percent hybrid market?

MR. SILSBEE: No, we're not.

PRESIDING MEMBER BYRON: In fact, when we met recently with Southern California Edison, they indicated during the long-term procurement proceeding -- and forgive me, I don't know their numbers at the PUC -- that they actually, the company was interested in not having self-bidding into those requests for offers, is that correct?

MR. SILSBEE: Yes. We've thought a lot about the notion of head-to-head competition. And in our view, a utility rate-based investment is very difficult to compare to a competitive IPP project because of the difference in the risk streams to our ratepayers.

And we would rather not go down the path of attempting to find ways to create a fair balance involving a head-to-head process, but just simply say where we want to focus our efforts on new procurement is in things that the competitive market won't provide to our customers.

PRESIDING MEMBER BYRON: I think we've elicited another question, if you will.

ASSOCIATE MEMBER PFANNENSTIEL: Yeah,

and that was the perfect segue to what I was going to ask about. When you say where the market won't provide, is that how you're thinking about your rooftop solar investment where the utility will own the rooftop solar, I don't remember how many megawatts you ultimately expect this to build out to --

PRESIDING MEMBER BYRON: I believe it was about 230 megawatts.

ASSOCIATE MEMBER PFANNENSTIEL: A big program.

MR. SILSBEE: Yeah, that's about right. Yes, that's an example.

ASSOCIATE MEMBER PFANNENSTIEL: And how did you evaluate that? Against what? Was that evaluated against other supply options in your procurement? Was it just evaluated in terms of, well, how was it -- what led you to decide that this was a good utility investment?

MR. SILSBEE: I don't believe we filed any sort of definitive cost effectiveness evaluation with the application. We've been asked to provide some supplemental testimony on that regard, which we'll file in a couple weeks.

One of the concerns is that the kind of

investment that's being encouraged by the California Solar Initiative is all-scale. Those projects tend to have fairly large overhead and installation costs. They don't have economies of scale.

And so what we're trying to accomplish, I believe, with the rooftop solar is to find a way to install solar facilities for lower cost than some of the policies the state is currently pursuing.

ASSOCIATE MEMBER PFANNENSTIEL: Now, this turns out to be, and I actually think it's a very innovative idea and would like to see it go forward, but if it turns out to be something that really does work, through economies of scale and driving down those costs, there are a lot of other rooftops in southern California where this could be applicable.

And so I assume there would be many other potential, I mean basic economics would say if there's a market there somebody else will come into it. And then presumably sell that power back to Edison.

It's being characterized by, I think, one of the Edison press releases as essentially, you know, rooftop power plants. So that would mean that there could be some merchants building these same kind of rooftop power plants, assuming that your model shows the costs can get down low enough to do that.

At that point, then, it is something that's competitive. And, you know, would it ever be then coming into your procurement process as a possible other resource?

MR. SILSBEE: Well, to the extent these investments become competitive for the private sector, there certainly are -- all source solicitations are open to, you know, renewable resources, as well as conventional generation --

ASSOCIATE MEMBER PFANNENSTIEL: But then it would beg the question of whether Edison would continue to be building rooftop solar if it is something the competitive market will. That was really my question.

MR. SILSBEE: And I guess my observation from the statements that we've made in the LTPP proceeding is probably not. But I've not discussed that with any of the officers at Edison to know what their long-term plans are specifically with regard to rooftop solar.

ASSOCIATE MEMBER PFANNENSTIEL: Just curious. As I say, I think it's very creative. I'm glad to see it happening. thank you.

MR. SILSBEE: Okay, you're welcome.

PRESIDING MEMBER BYRON: Thank you.

I do not have any other cards, however the public comment period if open. Ms. Turnbull, we'd love to hear from you.

MS. TURNBULL: Commissioners and Staff, I'm Jane Turnbull; I'm here on behalf of the League of Women Voters. I was not planning to make any comments today, but I have found --

PRESIDING MEMBER BYRON: I've heard you say that before, but we always --

MS. TURNBULL: I know.

(Laughter.)

PRESIDING MEMBER BYRON: -- we always hear from you. And we like to.

MS. TURNBULL: Something opens up at these meetings, which is really, you know, a testimony to the effectiveness of the meetings.

Interested to see the number of references to the impact of local permitting on long-term procurement. And I think, at least as I came into this meeting, I had not tied the two together. But I think there is a tie here that's really important. You know, one of the issues being the reluctance to plan, you know, into a 20- or 30-year period.

The League has really been supportive of regional planning. We're very interested in getting our local counties to include an energy element in their general plans. And they're going to only learn to do this if they realize that it's going to be a significant component of those plans, and going to have an influence in the long term.

So I do think that at this point it's important to recognize that there is a direct link between long-term planning on the part of the state and the local planning concerns.

PRESIDING MEMBER BYRON: Very good. Any other comments? Yes, please.

MR. CHEN: Good afternoon; thanks for the opportunity to comment. I'm Cliff Chen, Senior Energy Analyst with the Union of Concerned Scientists.

Just a brief observation that I wanted to make about the need generally for evaluating risk in utility planning and procurement decisions.

First of all, I want to thank Mr. Ringer for what I thought was an excellent report. I thought it was very fair and balanced and did a very good job of showing both the pros and cons of adjusting the discount rate to better account for risk in these decisions.

The take-away message for me of the report was that while there may be disagreements along, you know, utilities, academics and consultants about whether it's appropriate to adjust the discount rate to better evaluate risk, there is universal agreement that this is something that we need to do, and that we probably need to do better from now on.

So, I would just encourage both Commissions to continue working towards tools, metrics, analytical tools that do a better job of accounting for risk in utility planning and procurement decisions. Whether it's adjusting the discount rate or going with a certainty equivalent method, or -- what was the other one -- or portfolio analysis.

We're concerned generally that the sort of historical track record of using sensitivity analysis to look at risk is insufficient to fully capture the tradeoffs between minimizing expected cost and managing risk.

One of the issues with sensitivity analysis, excuse me, is that I think policymakers tend to default to the basecase or the most expected case or most likely case, when they make decisions, and that case is usually as case that largely ignores risk.

So I would strongly encourage both Commissions and the utilities to continue working to develop tools that more adequately capture and evaluate these tradeoffs. And to do so as quickly as possible.

I think the 2007 IEPR was exactly on target in making the recommendation that these tools and metrics needed to be more fully developed and fleshed out in the next set of long-term procurement plans.

Thank you.

PRESIDING MEMBER BYRON: If you wouldn't mind, when you say sensitivity analysis, are you saying that synonymous with the scenario analysis, or are you thinking differently there?

MR. CHEN: Well, when I say sensitivity

analysis I guess I'm referring to essentially scenario analysis where, you know, certain assumptions that tend to be the most uncertain are adjusted over a range.

So things like, you know, different natural gas price scenarios, things like different carbon price scenarios.

So, you know, utilities in their long-term plans, they might do one sensitivity analysis for high and low natural gas prices. They might do another sensitivity analysis for high and low load growth. That is what I was referring to.

PRESIDING MEMBER BYRON: Mr. Chen, I'm not an economist, I have to admit that right up front. I mean clearly what we're interested in with regard to the social discount rate is trying to get renewables a fair shake in this analysis. Giving them an equal footing.

And we're not meeting our renewable portfolio standard goals, and I don't think it's a secret that this Commission is having some influence at the state level, and we fully anticipate that we'll be moving to higher renewable goals.

So, taking everything that we've learned here today, that I've learned here today about the social discount rate and its importance in doing this kind of analysis, that it informs policy.

I guess my question to you had to do more with the importance of the sensitivity analysis versus the analysis that uses the social discount rate.

Do we have to look at both, or does one take priority over another? Because if we're just arguing what that rate is, that seems to make the difference in determining -- to determine whether or not renewables stand up against natural gas.

MR. CHEN: Right. Yeah, that's an excellent point. I think if you were to use a risk-adjusted social discount rate then there would be less of a need to also do the sensitivity analyses at the same time.

That's not necessarily what I'm advocating for. I mean I think sensitivity analyses will continue to be a pretty important and integral part of evaluating different resource plans.

But at the same time we're concerned that doing that alone is not sufficient to fully capture the risks that customers face in this brave new world of escalating natural gas prices, and also a lot of uncertainty over future carbon regulations.

PRESIDING MEMBER BYRON: Yeah, so the Administration got quite worked up about 30 days ago about watching the price of natural gas. And then, of course, in the last 30 days it's plummeted. A lot of volatility there.

Thank you very much for being here; thank you for your comments. I hope you'll provide written comments, as well.

MR. CHEN: Thank you very much.

PRESIDING MEMBER BYRON: Thank you. Any other public comments?

Commissioners, do you have any closing comments?

ASSOCIATE MEMBER PFANNENSTIEL: None.

PRESIDING MEMBER BYRON: I will provide some short ones. As I listened to all the excellent input that we received here today, good presentations, good comments, I want to thank you all for being here.

Clearly there's different constituents in play in all of this. I quickly wrote down, obviously there's ratepayers, and we're always concerned about reducing their costs. There's investors or shareholders, and we're always interested in trying to maximize their profits.

And the environmental concerns are paramount here at the Energy Commission clearly in the siting of power plants.

This Commission's goals, I think, is to try and balance all of those, and at the same time bring into play the policy goals of the state. Clearly long-term procurement and long-term procurement planning and the procurement process tied to many of those goals. In particular, renewables; it ties to the competitive wholesale market, which we asked a lot of questions about today in that regard.

And I think it also ties to the implementation of our goals for combined heat and power and energy efficiency, just to name two more.

So this is an extremely important topic. I'd like to thank everybody for your input here today. And we will be formulating our IEPR soon in draft form for Committee review, won't we, Ms. Korosec?

MS. KOROSEC: We will, definitely.

PRESIDING MEMBER BYRON: Did you want to say anything before we close?

MS. KOROSEC: The only thing I wanted to do is remind parties that written comments are due on August 25th.

PRESIDING MEMBER BYRON: Thank you. With that, we'll be adjourned.

(Whereupon, at 2:30 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 8th day of September, 2008.

PETER PETTY