STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

```
In the Matter of:                     )
                                      )
Preparation of the 2007 Integrated    )
Energy Policy Report (2007 IEPR)      )
                                      )
Use of Portfolio Analysis in          ) Docket No.
Electric Utility Resource Planning    ) 06-IEP-1M
_____________________________________)
```

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, JUNE 4, 2007

9:05 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Chairperson

John L. Geesman

Jeffrey D. Byron

ADVISORS AND STAFF PRESENT

Tim Tutt, Advisor

Kevin Kennedy, Advisor

Melissa Jones, Advisor

Lorraine White

David Vidaver

Michael Ringer

CONSULTANTS PRESENT

Steven Ostrover
London Economics International, LLC

ALSO PRESENT

Todd Strauss
Pacific Gas and Electric Company

Manuel Alvarez
Southern California Edison Company

Raymond Johnson
Edison International

C.K. Woo
E3

Osman Sezgen
Pacific Gas and Electric Company

Robert Anderson
San Diego Gas and Electric Company

ALSO PRESENT

Michael Schilmoeller
Northwest Power and Conservation Council

Serkan Bahceci
London Economics

I N D E X

P R O C E E D I N G S

9:05 a.m.

CHAIRPERSON PFANNENSTIEL: Good morning. This is a staff workshop on the use of portfolio analysis for electric utility resource planning. And it will be overseen by a joint Commissioners Committee of the Integrated Energy Policy Report and the Electricity Committee.

I'm Jackie Pfannenstiel, Chair of the Commission, and Presiding Commissioner on the IEPR Committee. To my right is Commissioner Byron, who is the Presiding Commissioner of the Electricity Committee. To his right, Tim Tutt, my Staff Advisor. And to Tim's right, Kevin Kennedy, Commissioner Byron's Staff Advisor. To my left is Commissioner Geesman, who serves on both the IEPR and the Electricity Committees. And to Commissioner Geesman's left is Melissa Jones, his Staff Advisor.

With that we have a very full and meaty agenda, so why don't I turn it over to staff. Lorraine, do you want to do the honors.

MS. WHITE: Yes, ma'am, thank you. Good morning, everyone, and welcome. My name is Lorraine White; I'm the Program Manager for the

Integrated Energy Policy Report proceeding.

Today, as the Chairman has mentioned, we will be looking at portfolio analysis in the electric utility resource planning.

Just a few announcements before we begin. We do have a snack shop on the second floor in case anyone wishes to get some refreshments. We also have restrooms that are just out the double doors to the left and also behind the elevators on the right.

In the event of an emergency we ask that everyone calmly proceed with staff out the building and to the park kitty-corner from the Energy Commission here until it is all safe to return, at which time we'll come back and continue on with the workshop.

Materials for today's workshop can be found out in the foyer. We have copies of the slides and the agenda. It's a rather meaty agenda. We're hoping that all of you will participate and provide us input. It's very important for us to look at all of the issues that we possibly can related to portfolio analysis, and welcome your input.

For those who are not able to attend in

person we have provided for both webcast, visuals that are available through our website; and also a call-in number so that questions or comments can be made. That number is 1-800-857-6618. You can also hear the audio through the webcast in case you do not wish to actually call in.

For those that will be with us today wanting to make comments and ask questions, there are points throughout the agenda in which we will be asking for those. And welcome any input.

The notice provided for today's workshop laid out the agenda in general terms; and also provided a series of questions of interest that staff is exploring as we go through and look at issue related to portfolio analysis and its application in electric utility planning.

Staff will be providing a background on utility planning and also on the portfolio analysis, itself. We'll be looking at issues related to the status quo utility planning; and then how modern portfolio theory might actually fit into improving resource planning for the future.

We'll be hearing about the LBNL 2005 study and the conclusions that are provided therein. We'll be hearing from the various investor-owned utilities. We have invited PG&E, SCE and SDG&E to provide comments.

We'll also be looking at certain case studies which actually demonstrate the application of portfolio theory, and in particular, we'll be hearing from the Northwest Power Conservation Council.

Finally, we'll be looking at implementation issues. And if we were to be using portfolio analysis in California, what it might take.

The workshop today is a part of the overall 2007 Integrated Energy Policy Report proceeding. And I provide this slide to give you a sense of where we're at in the proceeding.

We have been, over the last several months, conducting a variety of workshops. This is one such workshop. These workshops will actually continue well into July from the data-gathering side, trying to develop our analysis and produce our reports that will be the foundation on which the Committee, chaired by Commissioner Pfannenstiel, in which they will develop the draft Integrated Energy Policy Report. We're targeting late August.

Additional hearings will be held on that document to get refining input. We will be producing the final Committee draft early October so that we can adopt it by the Commission in late October, in time to transmit it to the Governor and Legislature by legislative deadline of November 1st.

All of the information regarding this proceeding can be obtained on our website. You're always welcome to call me with general comments. Mike Ringer is the lead for staff on issues related to the portfolio analysis. And his contact information is here. You can also find all this information on the Commission's website.

So I would like to introduce staff now to provide input. Dave Vidaver.

MR. VIDAVER: Thanks, Lorraine. Good morning, Commissioners, ladies and gentlemen. Thank you for coming today.

Prior to the passage of AB-1890 in 1996 resource planning in California's electricity sector was characterized by relative certainty. With one exception, utilities owned and operated generation. Even that exception qualifying facilities, created under PURPA, had financial incentives that led to their providing stable amounts of energy and capacity year after year.

This allowed planners to rely on estimates of available energy and capacity; and contributed to stable energy prices.

After the 1976 ban on instate nuclear development, natural gas emerged as the universal choice for fueling new generation. The availability of natural gas under long-term, fixed-price contract meant that the fuel-cost risk associated with operating these plants was minimal.

In sum, planning was characterized by limited choices and low financial risk. In this environment least cost was understandably the frame of reference for utility planning.

Subsequent to AB-1890, planning was removed from our vocabularies, only to re-emerge from the ashes in the 2000/2001 energy crisis in an entirely new environment. Increased reliance on natural gas for electric generation, especially as a swing fuel, in combination with regulatory changes in the natural gas sector, has led to substantially greater volatility in natural gas prices, and as a result, in marginal electricity prices.

Merchant generators appeared on the scene, or didn't, leading to volatility in both operating and planning reserve margins. And a further increase in the volatility of marginal electricity prices.

It also meant that planners could no longer rely on the presence or absence of generation in any specific location or set of locations in estimating the benefits of future upgrades to the transmission grid.

Increased concerns about global warming and the environmental impacts of energy consumption led to the possible imposition of financial costs for greenhouse gas emissions, introducing yet another uncertainty into the planning process. With AB-32 this possibility has been realized.

Non-utility ownership, along with renewable energy requirements, has meant a more complex procurement process. And finally, from the utility perspective, retail competition has created uncertainty with respect to future load obligations. And with load migration the necessity for regulators to design mechanisms to insure recovery of stranded costs and to fairly allocate system reliability costs.

While planning today is characterized by a multiplicity of choices and increased risk, this is only likely to intensify over the next decade and beyond. Natural gas production in the lower 48 states is projected to decline, requiring that we increasingly turn to frontier resources such as those located in northern Canada and others only accessible through importation of LNG.

Lumpiness and time lags associated with the necessary infrastructure development may further exacerbate price volatility.

These global sources of LNG can be expected to be dominated by a handful of countries, many of them politically unstable, raising the possibility of price-setting behavior by exporters.

We have, through SB-1368, and ultimately AB-32, made commitments to wean ourselves of dependence on the highest emission resources to meet our energy needs over the next decade and beyond. These will have the greatest impact on selected publicly owned utilities who currently rely on coal they own or have under long-term contract for a significant share of their baseload energy needs.

But other utilities as well, including the investor-owned utilities, will need to both meet load growth and reduce their greenhouse gas emissions; and will have an increasing number of potentially cost effective generation options for doing so.

And increasing number of renewable technologies will become cost competitive at expected gas prices. Many of these will be dispatchable and thus provide products largely provided today by fossil fuel generation.

Coal-fired generation with carbon sequestration is also likely to be an alternative, taking advantage of a natural resource of which we have an abundant supply.

In sum, there will be an increasing need to characterize and discriminate between alternative resources and technologies in an environment, itself, characterized by risk and uncertainty.

Finally, there will be an increasing need for baseload energy sources. Additions to the state generation portfolio in the past five years have been predominately gas-fired combined cycles designed, and certainly financed, to operate around the clock.

This parallels the current portfolios of the state's IOUs, which are baseload rich with must-take resources, including their nuclear assets, the newly built gas-fired combined cycles, qualifying facilities, and 4500 megawatts of baseload must-take DWR contracts.

However, as load growth occurs and these contracts expire in the first half of the next decade, the IOUs will increasingly need baseload resources.

Decisions regarding the composition of the state's portfolio cannot wait five or ten years, however. As the choices we make in the interim, whether they be related to procurement or basic research, will lead to the construction of resources that we will use for the next 30 or more years.

Portfolio planning, whether it is conducted at the utility level or at the state level, has historically been treated as an optimization problem subject to constraints. Some of these constraints are imposed by the physical system, including the need for dispatchable resources, to respond to changes in demand or reserves, capacity in specific locations, to meet reliability needs, the need for voltage support, black-start capability, et cetera.

Other constraints are regulatory or legislative. For example, the threshold level of preferred resources that the utilities are expected to procure.

Given the changed environment in which planning now takes place, there is an increasing need to consider this optimization as optimization under uncertainty. And to give due consideration to the various risks to which ratepayers are subjected, including those of potential long-run increases in the price of natural gas and the costs of greenhouse gas emission reductions of uncertain magnitude.

This need was articulated in the Energy Commission's 2006 Integrated Energy Policy Report. And the importance of these risks has been acknowledged by others, as well.

While the plans developed by the utilities for the CPUC's long-term procurement proceeding are not necessarily solutions to optimization problems, at the CPUC's request they do contain selected risk assessments for the portfolios that were developed. And I'd like to thank the utilities for coming here to discuss these today.

But the uncertainties that we face are such that an optimal portfolio, in the classical sense, one based on expected values of major drivers, may expose ratepayers to substantial risk. A least-cost portfolio, least-cost given a middle-of-the-road future, may lead to unacceptably high costs under a multitude of other equally plausible futures.

In order to determine if a given portfolio is robust to a large number of portfolios, it's necessary to evaluate it against each of those futures.

Fortunately, advances in computational capacity during the past ten years have made this possible. Software tools have been developed which allow users to look at large numbers of potential portfolios and futures, thousands of each, and millions of combinations thereof.

This is not to say that these tools can

be purchased off a shelf. Existing tools must be adapted and augmented for application to portfolio analysis. The Northwest Power and Conservation Council has done this in developing the fifth power plan for the Northwest. They have graciously consented to discuss their analysis and their model with us at today's workshop.

London Economics will also present several case studies of resource planning and the planning process in other regions, and what lessons might be learned from them.

In the absence of questions or comments I'd like to now turn the podium over to Mike Ringer of the Commission Staff who will briefly summarize the planning and procurement processes of CPUC jurisdictional utilities and articulate some of the major concerns regarding this status quo. Thank you.

MR. RINGER: Good morning. I'd just like to briefly go over some of the long-term planning in California as it's currently done, just to provide a quick overview.

Assembly Bill 57 requires investor-owned utilities to resume procurement. This was passed some years ago; and the California Public

Utilities Commission has a long-term procurement proceeding. The current one is underway. And in this AB-57 basically requires several different things from the utilities in their plans.

They do have to look at price risk. They have to describe the types and amounts of products that they have to procure, including the duration and timing, range of quantities of each product. They have to talk about their risk management policy and describe it. And there is a requirement to achieve diversity and renewable goals.

There have been additional CPUC decisions in addition to the actual legislation that does add further constraints and requirements regarding renewable annual targets, contract term duration, volume limits and standards, integrating energy efficiency, demand response, distributed generation, renewables and QF power.

Also there's requirements for local reliability that each of the utilities have to meet. And they have to meet a planning reserve margin and demonstrate that they have met that margin for the summer months a year in advance, and then one month prior to each month for their complete hundred percent that they meet their planning reserve margin.

Now the long-term procurement proceeding, the utilities do start by identifying the amounts of their customer needs; what the need is going to be over the next ten years. They split this out into the amount and timing of power products that they need in terms of energy, capacity, resource adequacy, ancillary services, if there's any black-start needs that have to be met.

They do this in terms of a procurement plan that they file with the CPUC. The CPUC does hold hearings and they take testimony, there's cross-examination. And then at the end of all this, the PUC approves the long-term procurement plan. And then the utility then goes out with RFOs to try to get the products that they need.

So, on our website we have posted discussion topics and questions of interest. And throughout the course of today's presentation certain of the questions of interest apply to different to the topics that we'll be discussing.

So, what we'd like to do during the workshop and following the workshop is get comments from interested parties regarding these questions.

So, as far as the long-term planning process goes, I think one of the major questions today is, as that process now exists in California, what role can portfolio analysis or any derivative thereof, how can it help the whole process of long-term procurement. And could it even help in the way RFOs are dealt with, how products are chosen, and could it benefit any portion of that process.

What I'd like to do now is go into just a brief overview of what some of the concerns are with the status quo, and that would be the long-term planning process. And this is not necessarily staff's positions, but sort of an overview of what you'll see when you go through the literature and some of the different aspects that people have brought up as to why things might not be the way they want them to be, or how they could be basically improved upon.

So the first one that you hear most often is the degree that the state is currently relying on natural gas, which as Dave mentioned, over the past several years has become fairly expensive and quite volatile.

You can see in this chart here that over the next ten years about, that the percentage of gas right now is fairly high; and until the year 2016, the percentage of gas drops off. But that's only because there's a lot of resources that have yet to be procured. And they haven't been identified yet. So those generic resources start off very low, since in the near term the utilities have a good idea of what they need. And over the next eight years there's going to be a lot more need that hasn't been identified.

So, what this tell us is that there's going to be a lot of opportunity to either get away from gas, or to continue with what we've been seeing in the past. And that is a lot of reliance on natural gas.

Over the past six years, for example, there's been 11,000 megawatts of capacity of baseload gas that's been added to the system in the state.

So this is an opportunity, one way or the other, to either go with gas or kind of try to reduce our dependence on it.

Other concerns with the status quo are

in the past that the emphasis has been on least-cost planning; and that that may not adequately consider risk. Least-cost planning, per se, will just take a look at the addition to the portfolio that's going to be the cheapest compared to all the other additions. It doesn't necessarily look at the entire portfolio.

And the least cost, in and of itself, doesn't say anything about the variability around the expected cost or the risk that's involved. Not to say that utilities don't consider this now, but that that is a concern that some observers have talked about.

And another one is the method of present valuing costs. This is related to the capital asset pricing theory which, according to some observers, the more risky an income stream is or a cost stream is, you'd want to present value that different than a cost stream that's more certain.

So in the sense of natural gas compared to another type of alternative that doesn't have such a risky cost stream associated with it, the argument here is that you would not want to discount the risky cost stream as much as the other cost streams. And that by discounting it at too high of a rate, then you have an artificially low present value for natural gas. And therefore, that may give it an unfair advantage to renewables.

Another concern is the use of forecasted natural gas prices instead of the use of market prices. The concern here is that forecasted prices may not capture a hedge value. If you're looking at renewables, or in fact, just a long-term contract with gas, one way to hedge future prices is, of course, to lock in a price, or to sign a contract with a resource whose fuel costs or overall costs is not linked to the price of gas.

So if you do then take a look at a natural gas price stream that's forecasted and it does not capture hedge value, you're actually comparing apples to oranges that way. So that's an additional concern.

Another aspect is the current use of risk analysis. And this is, when I'm talking about this, I'm talking about the different methods used by the utilities based on value and risk. To the extent that they have to report to the Public Utilities Commission on the risk of their portfolio, they're looking at a portfolio that's already pretty much set, and they're looking at hedging that over the near term, various number of years, for example. And that this type of risk analysis use does not really affect the composition of the long-term portfolio.

And then as we'll see in a later presentation, the view of portfolios around the west planning processes in the western United States, it's typical for utilities just to consider a very small number of candidate portfolios when they're making their decisions. It could range from just a few to possibly 10 or 12. Most of the times they're a very low number of portfolios, and when we start talking about modern portfolio theory and constructing an efficient frontier, there are usually quite a large number of portfolios that are involved.

So, by artificially constraining the number of portfolios that you look at means that then you may not get the efficient portfolio that you might be looking for.

So these are just kind of a little laundry list of some of the concerns that have been brought up and that we hope to touch upon many of these today and in our future staff report.

So, does anybody have any questions up to this point, or comments that they would like to make? Todd Strauss.

DR. STRAUSS: Thanks, Mike. Todd Strauss, PG&E. Just a question about slide 14 where you had --

CHAIRPERSON PFANNENSTIEL: Excuse me; I think you need to speak into the mike so we can capture --

DR. STRAUSS: Oh, sorry. Sure. So just a question about slide 14, when you had the gas consumption over years, particularly for the generic resources. Just wondering what's the capacity factor for generic combined cycle unit say in 2015.

MR. RINGER: I'm not sure specifically. This was a compilation of all the three IOUs in California. So, it's whatever each individual utility had assumed for that.

DR. STRAUSS: Yeah, I just want to clarify because that relates, I think, to Dave's earlier point where he was talking about sort of around-the-clock usage for a combined cycle.

Because when we look at a generic combined cycle in 2015 or so, it has a capacity factor maybe 50 percent. It's not 85 percent. So I just wanted to make sure folks understood the gas burn we're talking about associated with the new dispatchable and operation-flexible units, it's not running as a baseload. It's, you know, designed to cycle daily and has an anticipated capacity factor much less than a baseload unit.

MR. RINGER: Yeah, this is total kilowatt hours. And as Dave mentioned, and as we'll see later, I think, that obviously there's different needs for capacity and energy among the utilities.

COMMISSIONER GEESMAN: Mike, on your slide 15, would it be safe to presume that the points that you make with regard to renewables would also apply to capital investments associated with efficiency?

MR. RINGER: Yes, to the extent that any sort of investment, as long as it's a certain investment, is a hedge. And so that hedge can come about in, you know, various ways. So, that would be a fair statement.

Okay, if there's no other questions,

we'd like to get into a little bit of background of the whole point behind today's meeting, and that is what is modern portfolio theory.

So, to do that I'd like to introduce one of our consultants from London Economics, Steven Ostrover. And he'll be talking about modern portfolio theory, and overview and its application to utility planning.

MR. OSTROVER: Good morning. I'll be overviewing the modern portfolio theory this morning. I'll go through the conceptual and empirical issues, but nothing in any detail. I mean to just run through the breadth of the material quickly, mostly to set up the forthcoming presentations that will go through the issues in more detail.

That said, if there are any questions, please ask them and we can get into any issue in more detail.

I'll start by very briefly overviewing the ideas of modern portfolio theory and how they've been applied in the financial industry, which is where they originated. And then talk about how they've been more recently applied in the electricity industry.

There really is one central idea behind modern portfolio theory. Some people call it portfolio analysis. And it really has become so ingrained in the popular mindset, not just for academics and for people that are directly involved in the trade, but for laypeople, as well.

And it's simply that the idea of diversification. The idea that when assets with different types of characteristics are combined, there's a beneficial effect.

More specifically, when assets that have different sensitivities to the various types of economic factors that drive performance of financial assets are combined in different ways there can be beneficial effects.

This was, several decades ago, a new and interesting idea, revolutionary in its way. At the same time it fit very well into what had been, even by then, a standard framework for financial analysis, which was one rooted in both return and risk. And the central idea being that assets that are more risky over time should be expected, on average, to receive a higher return.

The real contribution at the more operational level was the notion that there were distinguishable, both conceptually and empirically, two types of risk.

The first is so-called unique or idiosyncratic or diversifiable. It goes by different names. And the second is a more systematic type of risk.

The first type is, as all the different names imply, types that are unique to any specific financial assets there. The particular types of sensitivities that any one asset has to various economic factors.

And the second, within this overall body of risk, is a more structural systematic risk where every type of asset in an economy tends to move in specific ways. And this type of pattern is referred to as market risk and can be found in any type of security at all.

And the idea is to distinguish those two. And there are various econometric and statistical techniques for doing it. And the challenge, then, in constructing portfolios becomes eliminating idiosyncratic risk. Because when assets with different types of sensitivities where the idiosyncratic portions of the risk are sensitive to different economic factors, as they're combined the sensitivities cancel out.

And if you take this to the extreme and have enough assets and can develop large enough portfolios you can, at least conceptually, eliminate all the idiosyncratic risk. And then the overall risk of the portfolio reduces to just a weighted average of the sensitivity of the individual assets, the market risk of the individual assets.

And the basic fundamental idea is always that, as has been mentioned by Mike, and I think David, as well, the focus is very much at the portfolio level. An individual asset is evaluated not on its own, but with respect to the contribution it makes to the portfolio.

Down to some basic empirical issues. The framework is entirely one, again, of risk and return, so the challenges become measuring risk and return. Fundamentally we're always talking about forward-looking estimates. This gets confused sometimes only because forecasting is a difficult exercise always, and sometimes all we have is historical data to use.

And sometimes if we're not very confident about our ability to extrapolate historical data, we actually use historical data for the analyses. That's fine. Statistically you might like it or you might not. But don't be confused. Whether you use historical data or whether you extrapolate on the basis of that data, you always are making estimates about what's going to happen in the future. Both with respect to return and risk.

The standard measure of return in the financial sector is basically shown under the second bullet point. But more generally you look at some measure of the return, what you earn on an investment; that's represented by the P-subT-P-subT-1 over some period of time. And you divide that by what you paid for the asset initially, which is reflected by the term in the denominator.

There are other variations of this that are possible. But in the end, this is really very much the standard measure.

And what you do when you conduct the analysis is estimate returns over some period of time, as has been mentioned before. You then reduce that to a single measure through a discounting exercise. And the discounting factor matters a lot. And discounting mechanics are difficult in some ways, and various aspects are up to debate. But, for the record, there's nothing particular about discounting as applied to modern portfolio theory that's different from all the discounting issues that come up in more standard net present value calculations.

Risk is measured generally as volatility of returns over time, expected volatility over time. And the two standard measures are either variance or standard deviation -- there's a typo, it says volatility or standard deviation, volatility should be variance.

And then in moving away, again the focus is always on portfolio, so moving away from the measures of risk and return at the asset level, when you combined that into portfolio, the return on the portfolio is always a weighted average of the returns on the individual assets.

But that, of course, is not true for risk. This is the entire point of portfolio theory. It's not simply a weighted average of the risk measures of the individual assets. It depends on the so-called cross-correlations between the volatility measures for the assets. And when you find assets that are not well correlated, or perhaps even negatively correlated, you realize the benefits of diversification.

This is a standard picture you could find in any variant of this in any textbook on portfolio analysis, or modern portfolio theory. The basic idea is that you begin at the asset level; you define risk and return measures; and then you find various ways to combine those into portfolios.

And the red space is something of an opportunity space of portfolios. These are all the different types of portfolio combinations. And then the idea is to pick the ones that are most efficient. And there's a solid line that's towards the left and the top of the opportunity space, a portfolio which is the so-called efficient frontier.

And I should have mentioned, although it's probably clear, the axes are the expected return on the Y axis or the vertical axis; and the expected volatility or risk on the X axis.

And the idea is that the efficient frontier shows you all the different portfolio combinations for which you can't make any type of clear improvement. Meaning that you can't increase return without increasing risk, or vice versa.

the exercise then becomes one of picking an optimal point along the efficient frontier. And at least conceptually this reduces to nothing more than defining a risk tolerance. Whoever it is that's conducting it -- again we're still very much in the financial world -- whatever company or individual investor that's conducting this would make a decision about how much risk he or she wants to be exposed to; pick that point on the X axis; and then simply, as a matter of mechanics, go up and find the portfolio, the corresponding point on the efficient frontier.

That's the notion of portfolio theory as it's been applied in the financial industry. And several years ago it was recognized that you can take some of these ideas and apply them not only to financial assets, but also to real physical assets. And there have been applications in several industries. And one is electricity.

And there are several different ways in which these techniques have been applied in the electricity industry. We've broken it down into four categories. The first, and really the most straightforward is for a generating company, either an independent company or an integrated utility with a generating portfolio, to use this set of mechanics to make decisions about the optimal combination of generators.

And in this sense it's clear, where we were dealing with financial assets before, stocks and bonds, here we're dealing with generating units that generate financial returns. And the focus for a company analysis of this type would be very much on financial returns.

It's also possible that we'd want to do an analysis not at a company level, focused on financial returns, but we'd want to look at things from a customer perspective, which implies looking more broadly at an overall industry rather than the portfolio of a particular company. And perhaps also there'd be a need, in fact we'll suggest there is a need, to focus on a return metric that is not purely financial.

The third category, the third bullet point points to the possibility of looking not at individual generating assets, but at types of generating assets. And there are various ways one could aggregate assets. The most common is to do it by fuel types. So rather than look at every specific asset and determining a large number of portfolios that could be combined from a large number of potential generators, you aggregate these into categories defined by fuel types.

And then the fourth category just introduces the possibility of looking beyond generating assets, including transmission and distribution assets. And this has been done sometimes. And even looking beyond hard assets and doing a broader strategic analysis for a company.

The case studies that we'll be presenting later give instances of the first, the second and the fourth type of analysis.

What we're going to be mostly concerned with, as we proceed, not exclusively but mostly, is looking at things from the customer's perspective. So there are various return metrics that might be applied, particularly when dealing from the customer's perspective.

Again, just as a reminder, from a company's perspective the standard is to come up with something that's very closely analogous to the standard financial metric. And what's normally used, although there are variations for different companies, is something like the electricity price minus the variable cost of operation in terms of fuel and variable O&M. And just combining that by the investment cost.

And there are various ways to break this down over time, but you can clearly see that this is very similar, conceptually and mechanically, to the financial measure that was introduced a few moments ago.

Now, if you're looking at the customer's perspective, where you would look not just at the assets of a single company, but more broadly, ideally what you would want to do is minimize the burden on customers. And the burden on customers is represented most directly by the price that they pay. And there you could change the language and talk about minimizing customer burden, in which case you'd look at price divided by number of kilowatt hours; or you can talk about maximizing return just by flipping around that ratio. The mechanics turn out to be exactly the same.

The problem is -- and if this isn't clear you can ask, because I haven't perhaps shown enough to make this perfectly clear -- you can't really focus on price for traditional portfolio analysis mechanics. Because the price, even though the focus is on the portfolio, you always begin by looking at the returns and the risks at the asset level.

And if you're dealing with a price measure, this is not -- a market price, this is not differentiated across assets. So you're going to have exactly the same metric on every single asset in the portfolio. And there will be no benefit revealed from combining assets in portfolios if you use a simple price measure in this way.

So, as the next best alternative what's normally done is to focus on cost. And everywhere that price appears in the ratios I was just describing you simply replace that with a cost metric where you account for fuel, O&M and investment costs.

And you can either do this in a ratio form where you'll often see companies or regulators talk about minimizing revenue requirement statistics, rather than using ratios. And this is not ideal, because as we know in competitive markets, price is not always, across all points in time, perfectly cost reflective. So there is implicit in this an expectation or an assumption that over long periods of time costs will be a good reflection of price in competitive markets, but it is an assumption; and it's one that is unavoidable.

The question, again, from a -- when you're trying to develop an analysis from a customer's perspective is what should be the appropriate scope of the analysis. And the complication, the slight complication is that you want to look at customer impact at an industry level, but you don't just do the analysis for the sake of learning something academically. You want to be able to make decisions and implement some type of policy on the basis of the analysis.

The problem is that decisions about generators are made at the company level. So there are really two choices. One is that you can conduct an analysis at the company level, either direct a company to do it, or have somebody independent conduct the analysis at the company level.

And you could look to see how far the

company's existing portfolio deviates from something on an efficient frontier, and perhaps provide direction to a company to make adjustments.

But it does raise a question that is worth some consideration -- we can either discuss it today, or with some consideration after the meeting -- is whether companies should be expected to diversify their portfolio and target the efficient frontier.

And the idea here is that when we talk about companies diversifying they're very much doing it on behalf of investors and the returns that we're looking at are returns to investors. And most economists will tell you that there really is no need for company managers to diversify operational assets because investors can so easily diversify their financial portfolio.

And my sense is that this is true at a theoretical level. But as it turns out, this is an interesting area where it just seems to be an example of a slight economic irrationality. The empirical evidence indicates that companies do actually receive a benefit in the financial markets from diversifying away idiosyncratic risk even though conceptually it really doesn't seem that they need to do it. So it's just an area where you have to make your own decisions about what is the appropriate way to proceed.

But, in any case, it is true that whether or not you believe a manager should attempt to diversify, they generally do and markets tend to reward them for it. But we are really concerned more specifically with customer impact. And if we want to get to customer impact directly, the appropriate focus is at the industry level. And this raises a series of questions that we'll examine in more detail in some of the case studies.

Such as, if you want to perform it at the broader industry level, who performs the analysis, how do you get the data, how do you define customer risk preferences. And once you've identified any type of inefficiency that you want to move away from, how do you direct companies to make the necessary adjustments.

This slide covers some of the empirical issues associated with developing estimates of returns and volatilities and constructing portfolios to populate that opportunities base that were shown in the one graph earlier.

There are several different techniques for measuring both returns and volatilities at the asset level. You can, as mentioned earlier, rely entirely on historical data; not make any adjustments to it. And implicitly assume that the future will be just like the past. It's not recommended, but it's possible.

More commonly you see at least some trend analysis, some simple extrapolation of historical patterns. You can, and companies often do, apply more sophisticated econometric techniques, specifically time-series analyses and multivaried regressions.

And then the more elaborate forms of analysis or different types of structural models. And I'll talk about these in more detail. Simulation and/or scenario analyses.

Once you've got your estimates at the asset level, the next challenge becomes constructing portfolios. And there are really two ways you can proceed.

One is in an entirely analytical and rigorous way by defining every single cross-correlation between every asset in the portfolio and come up with what becomes a very big matrix. And you could estimate the cross-correlations with all the techniques described above.

And once you do that it becomes an entirely systematized and potentially easily automated process to construct that entire opportunity space we looked at before.

This is the most comprehensive approach. It's most often not done because it's difficult to estimate so many cross-correlations. More often the performance of the analysis identify a subset of portfolios they think fairly well, between them, reflect the overall set of characteristics of the broader opportunity space. And then analyze those in more detail with simulation and/or scenario analyses.

So let me just describe very briefly the basic mechanics of these two types of techniques, and then close out.

The basic idea, again, is that you want to build a structural model where you identify the specific sensitivities of different types of assets to different types of economic factors that determine the results, the financial performance of those assets.

And the first bullet point lists a few different types of so-called risk factors or driving factors that are often used in an electricity analysis.

And then you need to estimate the structural form. You need to define the causal relationships. And that most often is done with some type of multivaried regression analysis.

And once you've got those two exercises complete, you're then in a position to run something like a simulation analysis. And what this is, is you start with a distribution of the core, the driving risk factors. And then you just perform iterations where you take points from these distributions. And then run it through the structural model that you've identified. And in each iteration of the simulation you come up with a set of results for whatever independent variables you're interested in, the return and/or the risk measure.

And if you do this enough times you get a distribution, not just for the input variables, but also for the return and the volatility measure that you're interested in. And this gives you the basis to develop the kind of graph that we looked at a few moments ago.

The slight difference between simulation and scenario analyses is that with simulation analyses you assume a single distribution for the input parameters, the risk factors. With scenario analysis you take, instead of additional steps, to leave open the possibility that the future will be significantly different than the past. It's not just that you can't pick a specific point within a distribution, it's that the entire distribution might shift, over time. And I think Mike talked about the possibility of major shifts in the gas market over time, for example. And this would be one possibility.

And you just take a few additional analytical steps to account for the possibility of these major structural shifts in what you've identified as the key risk factors.

It's worth noting that while everything reduces to that two-dimensional graph, and I'll show you a version of it again in just a moment, for the electricity industry, the real benefit of this is all the insight, as is often the case that you get from the analysis.

And it's not a simple mechanical

exercise, even after you've developed the opportunity space in the frontier, to just pick points. It really does require a bit of nuance. There's as much art to this as science. And all the insights that's gained from the analysis should feed into that final decisionmaking.

And when you apply the types of mechanics I've just described and make the adjustments from the pure financial application to the electricity industry, you get something that looks like this. And the full opportunity space is not fleshed out in red. But in this case there are a couple of few different portfolios identified. And there's an efficient frontier that's highlighted. And there are two points on the efficient frontier that might be selected from.

And this is exactly the type of result you would -- result that would come out of the basic mechanics of an application of portfolio analysis to the electricity industry. And once this is done, there are two additional considerations, both of which will come up in the case study

One is that within a pure financial

application we really are only concerned with financial returns, and everything is easily reduced to financial metrics.

It's not so easy in the electricity industry. We're concerned with financial returns, but there may be other considerations, as well, environmental factors, for example, that we'd want to account for.

Now, again, conceptually there's no reason that you cannot, conceptually, take environmental concerns and find some ways to monetize those and estimate the financial impact. And in that way continue to reduce everything to financial estimates. In fact, this is often done.

It gets tricky, not just with environmental issues, but if you're concerned with things like the equity implications of various tariff impacts across the customer base. It's always conceptually possible to reduce these issues to numbers, but it's complicated.

So what's often done is the results of this type of analysis is taken, and then combined in a way that again combines art with science, with additional considerations like environmental and social equity, if that's the language that you like. And through a more ad hoc, less analytically rigorous process a solution is identified.

And the other point that needs to be -- that I'll mention in closing, is in addition to introducing these other considerations, with a consumer-focused analysis it becomes even more complicated to pick a point on the efficient frontier. Because you need to define a risk tolerance, not for a single investor or for an established institution, but for the broader customer base. And we'll touch upon that a little bit in the case studies.

Questions?

COMMISSIONER GEESMAN: How do you factor in, with a key variable like natural gas prices, the fact that while we may have a nominal bid on NYMEX five years out, you only have a liquid market about two years out. So that while you may have a forecast value for gas prices in year six, you don't have anybody in the market willing to give you a bid, let alone year 16 or year 26?

MR. OSTROVER: Yeah, I think the answer is that you would probably apply some combination of the four different types of analytical mechanics under the first bullet point on this slide.

And you'd want to use market data as a way of moving past the historical figures for, I think you mentioned you had that kind of data two years out. And after that you would begin to rely on different types of econometric analyses, for example.

And maybe you'd be comfortable running off the results of regression equations three to five years out in the future. Beyond that you might really believe that there just is no basis, no statistical basis for being confident about any kind of prediction. In which case you'd move into the scenario, the world of scenario analysis.

And you would -- we'll talk about -- we'll illustrate some of these mechanics in at least one of the case studies. You would consider three, or some small number, fundamentally different states of the world. And you would analyze systematically the impact that those differences and assumptions about the range of gas prices would have on the analysis.

And in the end it would all work its way into the volatility measure.

COMMISSIONER GEESMAN: In a regulatory context do these fuel-intensive technologies in an environment where we have a strong historical tradition of fuel-cost pass-throughs, and quite rightfully, I think, does that create a fairly immense moral hazard problem with fuel-intensive technologies where the utility may, on the basis of forecast or scenarios, think that it has a basis for making a good estimate of what fuel prices will be in year 15 or year 25, knowing full well that the regulator will have no real choice other than to simply pass those through to the customer.

MR. OSTROVER: Well, I hadn't thought of it in quite those terms. The issue is not just that the utility might be over-confident in its estimation. It's that there would be some incentive for the utility to give the impression of having more confidence than it actually does. Is that the question?

COMMISSIONER GEESMAN: Well, I think there's got to be an explanation for how we ended up as natural-gas dependent as we are today; and seem to be driving to a greater level of dependency. With a fairly high level of indifference as to the economic consequences on the customer.

And I'm suggesting moral hazard may be one of the primary reasons for that.

MR. OSTROVER: I don't know. That's a good question.

COMMISSIONER BYRON: Mr. Ostrover -- Ostrover?

MR. OSTROVER: Ostrover.

COMMISSIONER BYRON: I probably should assume Dr. Ostrover?

MR. OSTROVER: No, it's not actually, but --

COMMISSIONER BYRON: On a scale of one-to-ten, how important is transparency in the procurement process to the application of modern portfolio theory in the electricity market here in California?

MR. OSTROVER: Well, there was a point at the bottom of one of the slides about the importance of the exercise. Not just to come up with a simple two-dimensional graphic, but to provide insight into the underlying set of issues.

And, you know, I'm a guy that does analyses all the time, and I believe that that really is the fundamental importance of analysis. Not so much a specific answer reduced to a graph or a single number. It's all the insight that's gained from it.

So, my belief is to the extent this is an issue that -- to the extent we're going to take the perspective of customers with this type of analysis, and be concerned specifically with customer impact, the importance of transparency with respect to everybody being able to analyze the results and draw inferences from the results, is critical to it. It's foundational to the process.

COMMISSIONER BYRON: Thank you.

MR. RINGER: Okay, thank you. Oh, I'm sorry.

DR. STRAUSS: Todd Strauss, PG&E. I just wanted to clarify, I think it would be helpful going on to make sure we understand what we're talking about non-portfolio theory. And I see your focus on the efficient frontier. And I understand that part of non-portfolio theory.

But my understanding is there's another part of non-portfolio theory. I just want to make sure whether we're talking about that or not. And please me if my characterization is wrong. If there exists some kind of riskless asset, typically operationalized as U.S. Treasury bond. And that through leverage the borrowing or lending and typically operationalized (inaudible) that one could describe the portfolio in combination with the riskless asset, and other assets, and that there exists a unique market portfolio which the efficient frontier intersects with a tangent line created through that riskless asset at the borrowing and lending.

And it seems like your presentation doesn't refer to that piece of non-portfolio theory at all. I just want to be sure, is that something you think is part of the portfolio theory that I'm talking about? And how relevant is that to the electricity industry plans?

MR. OSTROVER: It's a good question. Thank you for raising it. This is -- we prepared a report that will be issued soon that covers this same territory. And we included the discussion and overview of the application of the financial industry of a riskless asset. And the basic idea is almost exactly as Todd described it.

And the only reason for leaving it out

now is just for the sake of economy and trying to get through the overview quickly. With the understanding that there really is no analog of a riskless asset within the electricity industry.

So, while this is an important piece of the mechanics within the financial sector, and is worth understanding just as a matter for the sake of general overview, when we're talking about applications to the electricity industry there really is no analog to appeal a riskless asset. So there's no extension of that basic idea for electricity.

MR. ALVAREZ: Manuel Alvarez, Southern California Edison. I actually have a couple of questions. On your, I guess it's your fifth slide you talked about the return metric for consumer portfolio. Can you give me some examples of what you're thinking about there?

MR. OSTROVER: Let me see if I can find the slide. I'm sorry, could you tell me again which -- describe for me which portion you're interested in.

MR. ALVAREZ: The fifth slide. No, go back one. Yes. Determine the outcome portfolio for consumers.

MR. OSTROVER: Yes.

MR. ALVAREZ: Can you tell me what you're thinking in terms of what the return metric might be?

MR. OSTROVER: Yeah, that's on this slide. Right. This is a slide where we kind of introduced the various types of analyses and the various perspectives that might be taken. And then there is this kind of very clear distinction between analysis that's conducted for a company at the company level where we're defining the portfolio as the assets that are owned by that company, which is perfectly appropriate if we want to analyze things from the shareholders' perspective.

But if you want to analyze the impact of a portfolio on customers, customers are exposed, if you like, not just to the impact of a single portfolio owned by a company, but by the set of portfolios owned by all companies that are participating in the industry.

So the implication is you just need to broaden the scope of the analysis and define your portfolio not as the assets owned by a single company, but the assets that are contributing to the overall industry.

And what we'd like to do, if we could, is focus very directly on the most specific measure of the impact of constructive portfolios on customers. And the impact felt by customers is the price that they pay.

But it's a small mechanical point, and I apologize because to the extent it's not clear, it's because I haven't gone through some of the underlying mechanics in enough detail.

But the basic idea is when we're looking at combining assets and portfolios what we're really trying to do is find areas where the assets are subject to different types of economic risks. And when those risks cancel out there's a beneficial impact on the portfolio.

If, when you're looking at individual assets, the return measure is always based on the same parameter, which is the market price, you really can't do any type of portfolio analysis at all.

So, for the sake of -- just purely a concession to the limitation of the mechanics. For the sake of analyzing portfolios from the customers' perspective, you need to move away from what would be the ideal, most direct measure, which is price. And then look at cost measure. And that's what the third bullet point --

MR. ALVAREZ: But fundamentally it's still a financial parameter you're advocating.

MR. OSTROVER: It's absolutely a financial parameter. It's just a cost rather than a price measure. And, again, the underlying presumption is -- to rationalize the analysis, the underlying presumption is that over time, and this is a reasonable presumption of a long timeframe, -- this is the reason, in fact, we moved towards market mechanisms, is that market prices will, over time, reflect costs.

Now there can be certainly moments in time where they don't. We've seen many instances of this. But the underlying presumption is that to the extent market prices over time reflect costs, this is a reasonable adjustment to make.

If we don't believe that's the case then we're going to be concerned about this analysis. But, again, as a practical matter, there just is no way to focus more directly on prices.

MR. ALVAREZ: Okay. I guess my second question is what bounds the possibility space.

MR. OSTROVER: Just the possibility of, just the possible combinations of individual assets. So, here, for example, this red space is the combination of portfolios.

You could imagine just plotting risk and return measures for individual assets. And if you did, what you'd probably see is a bunch of points that are a little bit -- that are further to the right on that scale.

And the reason is, again, when you combine the assets you expect that there'll be a beneficial effect on risk and that the combination will consistently move you to lower risk points.

MR. ALVAREZ: So each of the possibilities has a feasibility component to it that must pass --

MR. OSTROVER: Anything in the red space is just developed by combining individual assets. So behind this chart there might be, for example, 100 individual assets. And you would just systematically in an automated way combine those in every possible combination. And it would map out this space.

MR. ALVAREZ: Thank you.

MR. OSTROVER: Todd.

DR. STRAUSS: Yeah, just go back to slide 6. Now that we're talking on the (inaudible) aspects, it's important that the two dimensions you suggest return, in terms of kilowatt hours per price, per price of kilowatt hour, where costs -- and you talked about an optimization and maximization, my understanding then -- there's an expected cost as a -- there's a risk if you understand -- of cost --

MR. OSTROVER: Yes.

DR. STRAUSS: And in the portfolio here (inaudible) if one assumes that returns are normally distributed, that's all one needs to focus on is the expected value and (inaudible). But if one has the idea that customer cost and that return is not normally distributed, it seems like there are other -- of the cost distribution besides its mean in the standard deviation one needs to focus on.

MR. OSTROVER: Well, I'm not sure that I understood the question. Can you repeat just the last part for me?

DR. STRAUSS: Sure. In the standard financial efficient frontier theory, there's an assumption that returns are normally distributed.

And so therefore all it needs to focus on are expected return and standard deviation of return and the correlation.

But, if we think about customer cost as not being normally distributed the way the returns are in the financial world, it seems like the entire cost distribution may be of interest, not just its mean and its standard deviation.

MR. OSTROVER: Yes. The question you're raising, I think, goes back to the various ways that one might estimate returns and volatilities. When you're dealing with prices and other metrics for which there's a lot of data available, and prices come in, for example, from liquid markets, we can rely on traditional assumptions of, distributional assumptions of things like normal distributions. And that makes it easier to just apply standard econometric techniques.

When you're dealing with cost metrics, which is not as much data available, and not as much empirical evidence about the way these tend to be distributed, you don't have these nice statistical properties. So you're more likely to have to rely on simulation models and structural models.

The empirical bits get more complicated. But I don't think anything changes conceptually.

DR. STRAUSS: I guess, actually I think it does conceptually because in the financial theory all one needs to care about are the two dimensions, the expected return and standard deviational return. That's what the operation will address.

MR. OSTROVER: Yes.

DR. STRAUSS: -- customer cost, even if we just focus on cost and not these other attributes, one needs to focus on more than the expected cost and the standard deviation of cost.

MR. OSTROVER: Fair enough. And as I said when I introduced this slide, when you apply -- and tell me if this goes to your point -- when you apply this to the electricity industry there are factors such as environmental considerations and social equity that one might want to account --

DR. STRAUSS: I think as I'm saying that even when strictly focusing customer cost, the two dimensions here, expected returns and expected risk, expected risk is operationalized by the standard deviation, I'm suggesting for customer cost those two parameters are inadequate in thinking about the realm of the cost distribution to customers, because that cost distribution is not normally distributed.

And if it is normally distributed, then the financial theory would follow through. But it's not normally distributed; those two parameters is not about to characterize the full cost distribution.

CHAIRPERSON PFANNENSTIEL: Mr. Strauss, what other parameters do you have in mind?

DR. STRAUSS: Well, for example, one might think about the chance of one-in-ten of something happening; the chance of one-in-20 of something happening. Extreme percentiles.

One might look at other ways to measure the spread of a distribution. What's the difference between a 10 percentile and 90 percent. But I want to at least look at, to some extent, some aspects of the fuller cost distribution rather than assuming it's a Bell-shaped curve.

CHAIRPERSON PFANNENSTIEL: And Mr. Ostrover, how would you respond to that?

MR. OSTROVER: Well, this is exactly what we were trying to get to when we talked about the differences between, for example, simulation and scenario analyses.

When you do, even if you don't have distribution of properties, you would move to structural models like a simulation model. And then I said earlier that you might even take a step beyond that, if you don't feel confident that you can even estimate a nonstandard distribution based on historical data and whatever other insights you can apply.

But there's so much question about whether things will change fundamentally throughout the timeframe of the analyses, then you do what's called scenario analysis, which is meant to exactly identify the possibility. And incorporate within the analysis the possibility of a one-in-ten prospect, or some very unlikely event.

So I think it's an empirical issue we're discussing. I think that scenario analysis is exactly the way that you would address it. But I'm not sure if Todd agrees yet.

DR. STRAUSS: Yeah, I think it's more strikes to the heart of conceptually trying to apply financial theory to what we do with electricity planning.

MR. VIDAVER: Dave Vidaver, Energy Commission Staff. Todd, can I take a shot at it? Are you contending that maybe higher orders of the distribution become important and --

DR. STRAUSS: That's right, (inaudible) those extreme possibilities and, you know, other measures of spreading the -- standard deviation.

MR. OSTROVER: I will say --

MR. VIDAVER: Sorry, I just wanted to let you know that when the Northwest Power Council makes their presentation they're going to summarize a series of risk metrics that one might use to take into account higher order distributions.

(Parties speaking simultaneously.)

DR. STRAUSS: I agree completely. I just wanted to make sure my understanding is once we start doing that, we're not really talking about using the portfolio theory -- but perhaps some other kinds of methodologies. And the question becomes what are useful methodologies for, you know, electricity planning. That's a great topic. And I think that's really what we're here for, to discuss today.

But I just wanted to make sure that when we're talking about -- portfolio, it actually has a particular set of constructs.

MR. OSTROVER: Yeah, and I was going to say exactly what David did, which is in addition to the case study that he identified, there'll be at least one of our case studies, as well, that will get to this point. So we can pick up on it again.

DR. JOHNSON: Good morning; I'm Raymond Johnson of Southern California Edison. I wanted to get back to the question of feasibility, because in one of your earlier slides you talked about the possibility of determining the most efficient portfolio, and on how to get there from where you're at.

I mean this may be sort of somewhat outside of your presentation, but I wondered, you know, whether you could make some comments about feasibility.

If you look at your last slide where you talked about, I mean I know this are stylized results, but, you know, one could take that as an example and say, okay, portfolio E is where we want to be. Therefore we need to go to 40 percent, 30 percent hydro and 30 percent coal.

But then the immediate question is in California is it feasible to go to 30 percent coal.

So, how would you take that issue of feasibility into account once you've come up with the efficient frontier?

MR. OSTROVER: Well, I could offer some thoughts about it, but it is outside the scope of the set of issues I think we're trying to deal with today.

I do accept the question as a very good one, and it is the logical next step. Because once you do perform this analysis it's very likely you're going to find yourself with a portfolio that's not quite efficient.

And as mentioned towards the bottom of this slide, when you do this analysis, particularly, it's difficult even at the company level to decide how you're going to execute large-scale adjustments and shifts in strategy and major movements in portfolios.

But when we're dealing with an analysis at the industry level with a regulator or some other entity acting on behalf of customers, the question of how you move from one strategy and one foundational type of portfolio to another is even more complicated.

And I didn't really come prepared to address that specific issue today, although it's a critically important one.

MR. WOO: C.K. Woo from E3. In looking at that efficient frontier I'm quite puzzled by the expected return and standard deviation return. I believe what we are looking at here is the procurement cost at the end. That's part one of my comment.

And second, you mentioned something about if we use the price measure somehow you lost the measure of volatility, which I don't believe that's true, either, for the simple reason, suppose C.K.Woo Utility go out and contract a whole bunch of forward contract. And my forward contract procure must not equal to my daily, you know, resale obligation. So there will be surplus and there will be deficit every day.

So the spot price volatility plus my quantity of risk will enter into my procurement risk at the end of the day. So that's my part two.

And the last one is that the issue of feasibility. When constructing a portfolio and calculate the variance of the portfolio cost, one can pre-set the feasibility conditions. For example, I can put in, let's say, RPS, renewable portfolio standard target of 20 percent by certain year. Then any portfolio that would not meet that target I kick it out immediately as part of the optimization.

Then one can also vary that constraint and so that once you vary that constraint you would have a different frontier. So by systematically moving all the constraints one might face, then you have a whole family of portfolios, or I would say efficient frontiers. And it becomes, you know, mimi, mimi, momi, moo, and then you pick out which one you like.

So, the idea of drawing one single frontier and claim to have understood the tradeoff, I think is a good starting point. But at the end of the day when you do the calculation I think the set of constraints one has to put in must be carefully constructed.

And my last remark is I respond to Todd's part, I think that's a good idea, -- risk, high calculation is important. And in fact, that's quite a bit of work on that area. And looking at just expectation, cost expectation and cost variance, assuming that, you know, the nicety of symmetric distribution, sometimes it doesn't work.

We know that like electricity prices tend to have a very long tail, you know. When things go bad, man, they persist and continue to be bad. As we have seen many times.

So, anyway, those are my comments, based on the kind of toys I've been playing with.

MR. OSTROVER: Okay, well, they're good comments. Thank you. My suggestion is that since this really was meant to provide an overview and set the foundation for getting into more details, and since many of the issues that are being raised will come up again as we get into the detailed case studies, to move on to the case studies and then pick up on some of these issues.

MR. RINGER: Okay, as several speakers have mentioned, we're going to get into specific case studies of some utilities later on in the day. London Economics has done some case studies, and we're certainly going to hear from a couple of the California IOUs, as well as representatives of the staff of the Northwest Power and Conservation Council. And that should be extremely interesting.

Before we do the specific case studies I'd like to go over sort of a survey that was done by Lawrence Berkeley National Laboratory a couple years ago. And they're actually in the midst now of an update of that study.

So, I'll start with the 2005 study where they looked at western utility resource plans.

Okay, Bolinger and Wiser in 2005 looked at about a dozen resource plans throughout the western United States, and this is just a list of the plans that they looked at.

You'll notice that the California IOUs' plans are here. And at that time that was the 2004 versions, so we're not going to discuss those very much here, since obviously there's 2006 versions out now that are being discussed at the CPUC. But it did include quite a range of utilities. And I think there's a couple more that were added to this in the recent update that's being done right now.

What they did find is that the

construction of the portfolios were done by hand. In other words, the staff of the respective utilities pretty much put together portfolios that they wanted to look at. And as I mentioned earlier, these were usually fairly limited in number. When you're doing something this way you can't come up with, you know, hundreds or dozens of portfolios that easily. So it tended to be restricted to just a few portfolios.

Another thing that was done is a lot of times the portfolios consisted of resources that the planners felt passed initial cost or performance screening tests. So, this sort of might have had a tendency to bias the types of resources that were included in the portfolios. Since if you do it this way the planners might have a tendency to sort of weed out high cost, or whether you considered high-cost individual resources. It sort of goes against the whole grain of looking at a portfolio, the portfolio effect rather than individual resources.

So this does limit the universe from which the optimal portfolio can emerge. And as we were discussing, the efficient frontier is supposed to consist of the portfolios that are most efficient. And you may have a skewed efficient frontier, as it were. To the extent that you can even construct an efficient frontier with such a limited number of portfolios. So then the modeling outcome is not going to be optimal in that case.

Looking at some of the risks that were evaluated, a number of them were common to most of the resource plans. Very common to look at natural gas prices, wholesale electric prices, variations in retail load and departing load. Of course, hydropower is very important, especially up in the northwest. And environmental regulatory risks.

This slide also includes the manner in which some of these risks were included. Turns out that the planning over the past several years has gotten increasingly sophisticated towards the stochastic analysis has been used in the majority of these plans. Although scenario analysis was also used.

Just a quick overview of the different utilities, how they define costs and how they define risk. Looks like the present value of revenue requirements is a quite common measure of cost, whether it be annual costs or it could be mean PVRRs, it can be weighted averages, different things like that. But it does tend to be present value of revenue requirements.

Different definitions of risk, as well. And then we see off into the far column, different weightings of cost and risk. You may have no weightings, you may have 50/50. It could be qualitative. This all varies quite a bit, too.

Now, as far as fuel and carbon risk, they determined that it looks as fuel price risk has taken some precedence over carbon risk in these plans from 2005. And that is that the fuel risk was addressed earlier on than the carbon risk. It impacted the basecase results so that if you have a certain price outcome you may dismiss certain portfolios. Whereas if you took your carbon risk as important as the fuel price risk, that that might not necessarily happen. And you could lose some portfolios as a result of doing it in that manner.

They determined that carbon risk is probably the most important environmental risk. We'll see that in the 2007 update. And they were just concerned that the renewable portfolios might have been artificially or improperly screened out according to the manner in which you do you analysis. And by taking certain aspects of the analysis, by putting them earlier, it gives them more importance.

Some of their general conclusions are they found that a number of plans put a cap on the level of renewables. They felt that renewables should be evaluated at levels even above RPS requirements in certain states. That there's not necessarily a reason to cap the renewables, the requirements.

Too often utilities are only including wind as a renewable. And a broader array of renewables should be included, such as biomass, solar and different types of biomass, things like that. Just by using wind all the time you have problems, you know, with firming. And they found that some of the portfolios might include too much firming gas capacity, things like that.

I mentioned previously each risk or concern should have an opportunity to impact portfolio selection. So, if carbon risk is indeed something that's very important, it shouldn't be left just to the end to basically affect a few portfolios that might be left once that you get rid of a bunch because of price concerns.

Ratepayer risk preferences should be researched. We see that on the efficient portfolio frontier, or the efficient frontier. Each of those, there's not a single portfolio that you can pick out that is the best portfolio. They're all tradeoffs between certain levels of risk and certain levels of cost or return. So they suggest that ratepayer risk preferences should be delved into a little bit more deeply.

And last, they say that better and more consistent data presentations would allow for better external review. They found, in certain instances, that the process wasn't as transparent as it could have been. And actually did sort of single out California in that regard.

As I mentioned they are working on an update right now. This is some material that was presented just very recently in Colorado. They don't have a whole report out yet, but I gleaned what I could from the presentation.

They did include a couple of different utilities, a couple of additional utilities than they did in the previous study. Many of them are the same utilities. They updated the plans that they looked at. And they do have preliminary findings out that they presented in Colorado in April.

They find now that the majority of resource plans do look at carbon. And they did say that that's a very important aspect of the environmental risk these days. Many of these findings are the same or similar as they were two years ago.

They did find again that plans are eliminating or substantially modifying candidate portfolios prior to evaluating performance under carbon, for example. And again, if carbon is screened out too early, the full range of options are not available for consideration.

The next-to-the-last bullet pretty much goes to the same point, carbon analysis is secondary to cost in many cases. And they suggest that carbon analysis play more central a role in that broader range of carbon costs to be included. They found that there was fairly low carbon costs in many cases.

As far as constructing candidate portfolios, again consider a broad array of technologies, not just wind. Consider including higher amounts of renewables than may be required under law. Better analyze cost integration and transmission of renewables. Energy efficiency should play a little bit broader role than it has been. IGCC, integrated gasification combined cycle, and carbon storage techniques should also be included. Even if these costs are not well known now, they can at least be included with a variation in costs in the future.

And then again, the more portfolios you have, the more diverse types of portfolios you're considering, the better off you're going to be. And these, again, mirror a lot of the findings that they made in 2005.

And then proceeding on, again they go to transparency. And I guess I might as well say a word about the point that C.K. Woo brought up, and that was discussed also by Edison. If there are constraints, that the constraints can be included when you're constructing your portfolios to begin with. That'll have an effect on where the efficient frontier is located. But obviously you can only work with what you have, and as we know, that there's a fair amount of constraints in

California as far as what's already required.

So, as this study points out, just because something is required doesn't mean you can't look at higher levels of it. Obviously we wouldn't be including conventional coal in California or new nuclear, so that's off the table. That wouldn't be part of a portfolio that we would consider. And you would just expect that the efficient frontier that is ended up with would be different. Although what you can include would lead to the most efficient frontier that you could under those circumstances.

So that's pretty much what I have as an overview of what's being done in the western United States. Just to provide us with an idea of sort of some of the things that other utilities are doing.

As I said, we're going to get into more detail. So, are there any questions right now about this aspect? If there are not, I'd like to move into --

COMMISSIONER GEESMAN: Mike, your reference to the Wiser/Bolinger study on transparency in the western United States, you said that they made special reference to

California. I'm familiar with the study, and am I correct that they indicated California was on the less transparent end of the spectrum in contrast to the other western utilities?

MR. RINGER: That's correct. They found that the California plans had less information relative to the other plans that they looked at. So that's exactly right.

(Pause.)

MR. RINGER: So we're lucky enough to be able to have Todd Strauss with us today from PG&E. And I'd like to introduce him now, and he will talk about integrated resource planning at PG&E. So, thanks very much.

DR. STRAUSS: Thanks, Mike. And I appreciate being here, and actually pleased to be in this spot. It seems like the right time of the day. I wasn't sure if I was going to be treated -- PG&E was going to be treated as a case study or what.

Because actually we can talk about our 2006 long-term plan filed in December 2006, and amended in March 2007. And we can look at that as a particular case study. And we may look at it a little bit as a, you know, in terms of -- case study, but also I try to take a more broad perspective in terms of the integrated resource planning perspective at PG&E. And also demonstrate some methodological aspects.

So, again, I'm Todd Strauss, Director of Energy Policy Planning and Analysis at PG&E. And with me today is Osman Sezgen, who is Principal Integrated Resource Planning. And Osman actually did a lot of the work to operationalize these ideas in our filing.

So with that I wanted to start on page 1 here, talking about uncertainty. Because I think that's a big part of what we're trying to deal with and grapple with when we think about planning.

And so I just wanted to put a framework in for considering uncertainty. And this is in our long-term plan testimony, which I will have the privilege of being testifying on that later this week. Actually the hearings on the long-term plan proceeding start today at the Public Utilities Commission.

So we talk about short-term uncertainties; longer term commercial uncertainties; and structural uncertainties about the long-term kind. And I just wanted to put some examples out there.

So, price volatility. Short-term uncertainty as prices change from hour to hour, day to day, month to month, okay. We can look at weather-driven effects on load, hydro, intermittent resources. And shorter term uncertainties, daily effects, perhaps seasonal effects within the year. And outages of resources, forced outages, short-term events, okay.

When we look at uncertainties of a commercial type, of a longer term type, I'm particularly thinking about things like what's the online date for an anticipated resource like a Gateway plant that PG&E has under construction. Or a Colusa plant that we have under contract. Or a Russell City plant, okay.

And also, what's the retirement date for some of the plants that are in existence and have been for 40 years or so. Those are longer term. I think of those as commercial uncertainties.

And finally, I talk about a category of structural uncertainty. So, we think about market prices, and we talked earlier about well, there's market price signals today, but they may be subject to a variety of sudden shifts over time; sudden longer term gradual shifts over time; consumption patterns may change; supply patterns may change. And so these structural changes in market prices is a kind of uncertainty the audit must be considered in long-term planning.

Load growth, and particularly the growth over long term, is structural uncertainty. We think about the market availability of renewables and customer-side preferred resources, talking about energy efficiency, demand response, distributed generation. And basically the state has programs in place, and PG&E is actively working to implement those programs.

But when we go out and procure renewables or energy efficiency, or demand response, and I'm thinking of this from the procurement perspective, really we're relying on customers or the markets to give us some solicitation offers. And when we think about that, well, we can't control that. And so we need to think about how the market, how customers, how suppliers may respond. And that actually is pretty common that a lot of competitive industries and firms -- what's the market availability of those resources. So that's the kind of uncertainty we're very much focused on.

And finally, when we think about our particular portfolio, managing it over time, less so much about what's the overall regional need, but aspects of, you know, what's the particular need that we're planning for for our bundled customers, issues of direct access and community choice aggregation come into play.

So these are the kinds of uncertainties that we're thinking about when we're doing our planning.

On page 2 I just want to characterize in a very stylistic way how one might model uncertainty. We can ignore uncertainty. Uncertainty can be represented, basically have a basecase. And that may or may not be an expected case in a probablistic sense. My experience is the number of times folks actually calculate probabilities and that basecase equals an expected case is actually few and far between.

One can have a basecase with sensitivities. One can do a variety of scenario-based analysis. One can do probablistic analysis.

And I put it in a kind of hierarchy. It's not exactly a self-actualization hierarchy. I think it is one of increasing sophistication. That's not necessarily a good thing. It's just an aspect of these techniques.

And the real thing is well, there's a suite of choices for modeling. And what one needs to be doing is appropriate techniques for the appropriate circumstance. I want to speak to that in a moment.

So, when we turn to integrated resource planning at PG&E, talking about modeling the short-term uncertainties, so I'm taking the list from page 1, broken out price volatility, the weather-driven load, and hydro and separated it out from the weather-driven intermittent resources, how do we model price volatility.

Well, when we calculate risk measures, as alluded to earlier, such as to expiration value at risk, and that is we actually report that monthly to the Public Utilities Commission going out five years. But that's primarily oriented to be a short-term measure because the portfolio is static when one looks at that.

Price volatility is actually modeled

probablistically. We have a distribution of prices explicitly probablistic. And when we calculate energy positions, that is for a particular period, for July 2009, how long or short are we for energy on a delta-adjusted basis. So this is option-speak, option financial valuation framework speak for taking into account basically the uncertainty. So, in that sense, price volatility is modeled probablistically when we do that.

Now, when we calculate capacity positions and energy positions on an intrinsic basis, that means just looking at a particular set of forward curves, well, really that is just a basecase analysis, and that is a true expected case analysis off those forward curves.

When we look at weather-driven load and hydro, well, we do model that probablistically in our TeVar model; and that is something that's different from what we do compared to, say, what the financial houses do when they calculate value at risk. And we also account for weather-driven load and hydro when we calculate our energy positions on an option kind of oriented basis.

And when we basically take, as given, a

set of power prices and gas prices off the forward curves, we model it as basically a basecase.

Now, when we consider a capacity position, so measuring megawatts now, okay, there's this idea of a planning reserve margin out there. And the way one may think about it is this planning reserve margin is some attempt to account for those weather-driven uncertainties when one is measuring a capacity position, okay. And so that's the way I tend to think about the relationship between a capacity position and the planning reserve margin, how it accounts, or tries to account for that particular kind of uncertainty.

When it comes to intermittent resources and their supply is also driven by weather, so I think of wind and solar, it's not currently modeled when we're calculating TeVar or our energy positions, the uncertainty.

So we are taking basically some basecase profile, or perhaps an expected case profile, if the basecase is actually calculated formally. But the uncertainty in that intermittent profile is not included when we calculate TeVar or the energy positions.

And when we calculate our capacity position, there are a set of resource adequacy accounting rules and there's a planning reserve margin. So that's some attempt to account for the short-term weather-driven uncertainty with intermittent resources.

And finally, when we look at outages, well, outages actually are not currently modeled in calculating TeVar, and there's various questions and interpretations of whether it ought to be. But if one thinks about it from the strictly financial perspective, it ought to be excluded. And so we continually wrestle with, should we include outages or not when we think about the portfolio in calculating TeVar.

When we look at energy positions, how long or short are we, do we need to anticipate procuring or selling in the marketplace, we do adjust for outages. And, again, when one thinks about the capacity position, the megawatts for peak load say, well, the planning reserve margin, again, is some attempt to account for this uncertainty associated with outages.

So this is how I characterize short-term uncertainties and how we model them at PG&E in the integrated resource planning framework.

Commercial uncertainties. And so I mentioned two. The online dates for anticipated resources and retirements. Well, sometimes we model them probablistically. Sometimes we model them with scenarios. We usually model the online dates for anticipated resources as a basecase.

And so we anticipate today; here's our basecase, our reference case when this resource will come online. And really we have event-driven updates to that basecase. As one, you know, there may be permitting delays, construction delays, other events.

When it comes to retirement sometimes we model them probablistically. We often model them with scenarios. And we sometimes model them with the basecase. And the sometimes, the usually and the often depends upon the circumstances, the particular questions that are being asked.

When it comes to the structural uncertainties, and this is, again, on page 5. I'm just rehashing the list from page 1. These are really the thorny ones. The longer term ones which we actually there's a lot of out there. Maybe we know what we don't know, but more likely we don't know what we don't know.

And that actually is really important for a planner to be aware of. We don't know what we don't know.

So how do we represent what we might know about what we don't know, and try to not over-characterize it versus what we don't know about what we don't know.

So sometimes we use scenarios; and usually we model them with basecases and sensitivities. Okay. But we try not to ignore that uncertainty. We just want to be aware of that uncertainty. And also try to be aware of what we don't know and ar not yet aware of.

With that I want to turn to some scenarios that we put forth in our 2006 long-term plan. So our current long-term plan, we use scenario analysis. And on page 6 we basically have four different scenarios. We try to give them catchy names, not nearly as sexy and catchy as Cambridge Energy Research Associates has with their.

But there are various components on that. And I just reproduce on slide 6 the summary table that's in our testimony. And basically these scenarios are either region-related or maybe portfolio-related, say associated with re-contracting and so forth.

But we try to specify at some level of detail what the possibilities are, recognizing is this the entire scope of the uncertainty. No. This is some plausible set of uncertainties, okay. We have not attached probabilities to these, okay. But we want to basically try to frame the discussion in thinking about our awareness of uncertainties.

And certainly these are not the only four scenarios we considered. These are the four scenarios we filed. It was a 700-page filing, as it were. And so our analysis -- and so this is where I want to separate out our integrated resource planning from our long-term plan, as filed.

Because we try to look more broadly when we do the planning, naturally. And our long-term plan is in a more limited context.

CHAIRPERSON PFANNENSTIEL: Before you move off that line --

DR. STRAUSS: Oh, sure.

CHAIRPERSON PFANNENSTIEL: Those of us

up here with older eyes can't really read what's on the screen. So can you just give us a sense of what the four scenarios are, and how your variables are -- how you're looking at the variables on them?

DR. STRAUSS: Sure, sure, I appreciate that. And the point of having the table we produced wasn't to go over in detail, but to give you a flavor for what we've done. And it's in our testimony.

But scenario one, -- scenario two and three are certain variations off of current conditions in the marketplace. So we're using basically forward curves of a certain vintage to represent market price. We're representing the supply curves for preferred resources for energy efficiency and renewables and so forth, off what we are currently seeing in the marketplace.

And when we look at the other scenarios, scenario one and scenario four, they kind of try to be more at the boundary points; try to think broadly about, hmm, where might market prices go in the low end; where might market prices go in the high end; what might the market availability be of preferred resources. Particularly if the market price is low, what might the market availability be. That is in supply curve. I'll show you a snapshot in a little bit. Be it market prices were higher.

So, we also have long-term load growth varying across the scenarios, as well. Does that give you a flavor for what's in here?

CHAIRPERSON PFANNENSTIEL: Could you at least read the names of scenarios 1 through 4?

DR. STRAUSS: Oh, sure, sure. Okay. So these are the catchy names that we try to come up with. So scenario one says stranded costs; scenario two says current world, low preferred resources availability; scenario three, current world adequate preferred resources availability; scenario four is high-price, high-growth scenario.

CHAIRPERSON PFANNENSTIEL: Thank you.

DR. STRAUSS: Sure. Other questions on slide 6?

So when it comes to thinking about the market prices, here's slide 7, we look at the scenarios. So basically we have a graph at the bottom of the page. And on the horizontal axis is basically time, going from 2010 to 2016. And on the vertical axis is gas price in dollars per

MmBtu for that particular delivery year that we're looking at.

And you can see that these are PG&E citygate prices. They do vary by scenario. And scenarios 2 and 3 were certainly sort of current world where the forward markets were in June 2006. And scenario one is some attempt to represent a bit lower prices; scenario four some attempt to represent a bit higher prices.

And so we try to have sustained high and low prices in our plan. I note that we are not considering these four scenarios really any kind of shift in the slope of these curves. And what's known as sort of backward-ation -- the slope, is the curve increasing or decreasing, what's the slope of that.

And that's really not in this plan. I do know when you're considering rate projections having sensitivities, having scenarios that really think about the shifts in the slope, that actually becomes important.

That may be, you know, a different focus when we're actually thinking about well, what's our resource mix in the portfolio. So, again, depending upon the particular question one is trying to address, there's a particular reason to focus on particular sensitivities, particular scenarios than others. And there's a wide range of things to choose from.

COMMISSIONER GEESMAN: Those are pretty smooth curves, aren't they, Todd?

DR. STRAUSS: Smooth in the sense of?

COMMISSIONER GEESMAN: No rapid changes.

DR. STRAUSS: Right, yes. You know, you look at this, it's like one scenario $5 in 2010; declining to something a little less than $4 by 2016, the current forward curve, and --

COMMISSIONER GEESMAN: Has your experience over the last ten years been that tranquil on the fuel price side?

DR. STRAUSS: And there I want to distinguish between forward looking, expected value, which is what a forward curve has some representation of, versus a realized trajectory. And, of course, realized trajectory is going to be much much more jagged, absolutely, with short-term volatility and long-term structural shifts and so forth.

But if one said in 1997 what would I anticipate in 2000, right, for a forecast for even what the market forward was, it would be much smoother. In fact, you know, that's why the importance of super-imposing on top of expected values the range of uncertainty is critical. So I agree with you there.

COMMISSIONER GEESMAN: Yeah. I'm just thinking that I would presume the flood risk for Sacramento, historically over time, could be compressed to a flat curve like that, or a smooth curve. The seismic risk in San Francisco could probably be graphically represented the same way. Neither would capture the influence of volatility.

And I'm just wondering from a planning standpoint how one tries to capture that.

DR. STRAUSS: Sure. And, again, just looking at these prices is representing, in essence, the forward prices, or expected value prices. I'm sort of being loose here with the financial mathematics.

But the kinds of things you're pointing to, those event risks, if one would, we can look in our distribution of prices in just a moment, which is on the next slide. I think that may speak to your point a bit better, which is, oh, if we actually look at what's the spot gas price in

2010 now, okay, there may be a mean value of 792 from slide 7.

But that realized value in 2010, again just using today's forward market information, and basically taking option quotes of modeling applied volatility from them, and certainly there's a fair amount of interpolation, extrapolation here, and lots of technical details, but when one thinks about this distribution on page 8, it gives much more the sense that you're referring to in terms of the wider range of possibilities.

And so --

COMMISSIONER GEESMAN: How about if I went back to 1997 and looked at your ten-year forward curves that you were using for planning purposes then. What would they look like?

DR. STRAUSS: I hear what you're saying, and those would also be pretty flat, actually probably, you know, gas prices were about $2 MmBtu. But actually if one looked in 2000, in spring of 2000, for a five-year forecast of natural gas price at the 95th percentile, my recollection, the calculation I had done then was that it went from $1.50 to 9 bucks. So there's a lot more with, when one thinks about the inherent uncertainty that are revealed in market price signals today than just focusing on forward prices and expected values, themselves.

COMMISSIONER GEESMAN: Now, who bears the risk of that forecast in your utility supply planning?

DR. STRAUSS: In terms of bearing the risk of the forecast --

COMMISSIONER GEESMAN: Being wrong.

DR. STRAUSS: The forecast will be wrong. All forecasts are wrong. And so if the point is that who, you know, where do the costs eventually lie, the customers, right, are basically --

COMMISSIONER GEESMAN: There's no question about that, is there?

DR. STRAUSS: Absolutely.

COMMISSIONER GEESMAN: You've gotten every dollar expended on fuel passed through to your customers, haven't you, in recent history?

DR. STRAUSS: My understanding is that's correct. So that's exactly why we're doing this planning, which is to think about, well, customers are bearing this risk, and what is this risk. How do we quantify it; how do we identify it; how do we manage it. Control is a strong -- how do we manage that. That's the final.

COMMISSIONER BYRON: Mr. Strauss, going back to something you said a little bit ago, with regard to slopes of these projected curves, if I understood you correctly you indicated that slope was more important, positive-negative slope was more important with regard to tariffs. But that for portfolio analysis that it didn't make much difference.

Now, I'm wondering if we're really getting the full benefit of understanding the increased dependence upon natural gas fired power plants or renewables, when all these projected price curves have a negative slope to them.

DR. STRAUSS: Yeah, and that's going to be more precise in saying. If one is focused on, hmm, what will the change in rate from 2010 to 2011 be. The slope of the price curve is very important.

If one is said, one -- what's the level of what rates will be in 2010 or 2011, right, will it be 12 cents, 8 cents, 10 center. Then the slope matters less than the absolute level. That's the only point I was trying to make.

COMMISSIONER BYRON: Well, let me be clear, then. Why don't one of your scenarios include a positive slope?

DR. STRAUSS: Sure. And we did not do that in the 2006 long-term plan. That's a great thing to consider, and it certainly is something we have done analyses with other slopes, and that is something we can consider in future filings.

COMMISSIONER BYRON: Thank you.

DR. STRAUSS: Sure. So, if there are deficiencies in our current plan, there are many. And I just, you know, want to highlight sort of where we're at and what we consider, so. And particularly this is the focus on what we file.

So if we go to slide 9, again looking at scenario analysis, those four scenarios, one thing we looked at is the market supply for renewables. That is what's the supply curve quantities on the horizontal axis, you know, market price, the cost that we're seeing, the customers are seeing on the vertical axis associated with renewables.

And we have representations for that for each year of delivery. On slide 9 we have it for year 2011. And so you can see that we are varying, by scenario, the supply curve for renewables. This is what is meant by market availability.

And the triangles represent particular plans, particular candidate plans. I'll speak to that more in a bit.

COMMISSIONER GEESMAN: Now, if I recall, your 2005 procurement solicitation was the first implementation of the CPUC's 2004 long-term procurement decision. That decision said that renewables were to be the rebuttable presumption for all long-term procurement. Your 2005 solicitation elicited 50 responses, not a single one of them from a renewable project.

So, you know, what evidence is there that you know the first thing about supply curves for renewables if your solicitation implementing a key CPUC policy has been unsuccessful in getting a single response?

DR. STRAUSS: I hear you there, and I'd just note that PG&E has signed several dozen renewable contracts over the last four years. I think for 2006 our renewable procurement was -- I can't recall if it was 4 percentage points or something like that, off our load.

The particular solicitation I believe

you're referring to was when we were looking for dispatchable and operationally flexible resources. And renewable resources, in particular, have a hard time meeting the dispatchability and operationally flexible characteristics.

It's not that we're not looking for renewable resources; in fact, they're preferred. And, in fact, after we look at our quantities of renewable resources, and basically this is some attempt to reflect the cost effectiveness, the market availability of those renewables, but as we'll talk about in a little bit, I mean they're not plans, we actually go beyond that to procure additional amounts of preferred resources.

Still, you know, the system needs some requirement for dispatchable and operationally flexible. And that's why in that particular solicitation there were no renewable resources selected.

COMMISSIONER GEESMAN: Now, in your 2006 filing with the CPUC, if I'm not mistaken, you also put a 10 percent limit on the amount of wind that you would allow into your procurement plan.

DR. STRAUSS: I don't believe that's the case. Osman, perhaps you can -- my understanding of the portfolio that we have projected here in our long-term plan, it was projection about 50 percent wind, the incremental resources.

MR. SEZGEN: That's correct.

DR. STRAUSS: And I think that was largely based upon -- we basically looked at the CEC work, the Commission's work, for a mix of renewable resources, and so we included wind, solar, biomass and so forth.

COMMISSIONER GEESMAN: So you're not aware of any 10 percent limit on the wind that you would procure?

DR. STRAUSS: I want to be careful about that and say 10 percent of the overall portfolio?

COMMISSIONER GEESMAN: I believe that was the constraint that you imposed in your procurement filing.

DR. STRAUSS: Yeah. That could be a function of the overall portfolio.

COMMISSIONER GEESMAN: And why would you impose a constraint like that?

DR. STRAUSS: And at this point it was basically we actually -- there are a lot of operational issues with wind that I'll talk about in a little bit, that we actually don't know much about. And there was some attempt to try to understand and represent, to some extent, some of those operational issues that we're diving into in greater detail.

But, --

COMMISSIONER GEESMAN: And is that reflective of other utilities around the west?

DR. STRAUSS: I think we'll let the other, you know, California utilities speak for what they represent. But I think there are various -- the whole notion of what is the consequences for wind on a portfolio and system, I think, has varied across the west from in California attempts to say well, it's negligible integration costs, to in Idaho where it's, you know, $10 a megawatt hour. So I think it's varied across the west is my understanding.

COMMISSIONER GEESMAN: Are you aware of any other western utilities that have imposed a 10 percent constraint?

DR. STRAUSS: No.

COMMISSIONER GEESMAN: Thank you.

DR. STRAUSS: So we turn to page 10. I want to spend some time thinking methodologically rather than the particular case study, when we look at planning and procurement at PG&E.

And I know we talked about the particular application of modern portfolio theory this morning. I'd like to characterize the approach we have at PG&E to long-term planning and procurement as one as it's actually grounded in theory and application of something else called multi-criteria decisionmaking.

And that is if one looks at the efficient frontier, and in particular representing assets, resource choices, particular resources, as represented by having a cost dimension, and an expected cost and a risk, or standard deviation of cost, that seems incomplete, as was acknowledged earlier, and I think some of the other case studies will indicate that.

And so when we look to see how do we make systematic explicit tradeoffs, we actually have a variety of attributes. So each asset in the financial world really has a mean and a standard deviation and may have a correlation with each other asset in the portfolio.

Well, here, if an asset is a demand response program, or if it's combined cycle resource it has a whole vector, a whole suite of attributes. And that's one thing to note.

The other is that one of our goals in managing this portfolio on behalf of customers, when we think about reliability, we think about environmentally preferred resources. We think about low cost; we think about stable cost.

So it's really in thinking about these different dimensions that we're trying to achieve and really balance reliability, environmentally preferred resources, and cost components in thinking, in measuring that, and thinking about the whole suite of attributes associated with each particular asset or resource.

That's why, I think, the portfolio theory idea, certainly the efficient frontier is a useful one. But the other aspects of portfolio theory and operationalizing the efficient frontier aren't that useful.

So things about, well, say non-parametric production functions. Or, in particular, aspects of multi-criteria decisionmaking seem to be more important. And, you know, I cite some examples of that in what we've done, in particular request for offers. So in RPS, RFO and long-term RFO, we basically are measuring a variety of different criteria, considering possible resources along those dimensions and comparing them in a systematic way, using this theory and application.

In our long-term plan methodology, basically it's three steps. First we consider a variety of possible scenarios, 1, 2, 3, 4 here. We consider a variety of possible courses of action, A, B or C. And finally we're going to measure those outcomes on a variety of measures.

And we focus on four measures in our current long-term plan: reliability, customer rates, renewable resource and CO_2 emissions.

And so I think this framework is consistent with many of the case studies we'll be hearing shortly. And it's certainly an aspect of portfolio analysis. I don't necessarily see this as application of modern portfolio theory as other methodological frameworks in which basically there are a suite of possible states of the world that really may not be controlled. There are possible actions that basically -- that is within control. And there are a variety of outcome measures to assess the possible actions against those outcomes.

Recognizing in all of this, with all the numerical detail, we don't know what we don't know. So, on page 11, represent a snapshot operationalizing this idea.

So in our long-term plan we present four measures of outcome for each year in the planning horizon. So, one issue is the discounting and certainly aggregating cross-temporal effects. We actually try to look at things year by year to get a better feel for what's going on.

But the question becomes how does one aggregate that across time. That's an issue maybe we can talk about later. But we measure for each year of the planning horizon, here for 2014 is represented four measures for each of three candidate plans. Those are the rows. For each of four possible scenarios; those are the columns.

So you can see, for example, in the first box in the upper left for the candidate plan A in scenario 1, reliability was 2.5 days in ten years. That's basically a measure of loss-of-load expectation. I sort of colloquially think of that as the probability of a stage three outage, a stage three event, all right, where basically there are mandatory blackouts, rolling blackouts.

And typically is 25 percent, 2.5 days in ten years.

And so the rate, and this is a nominal rate in that year, and this is just the generation rate component, and includes a variety of, you know, public programs including the energy efficiency and demand side, other kinds of resources, not strictly just generation, 8.5 cents.

And the attainment, when we think about the fraction of our load, retail sales from renewable resources, 21.7 percent. And the CO2 tons in 16.3 million metric tons per year.

So you can see, basically we're measuring four things, three possible actions we're considering, four possible states of the world. On the right, basically some representation of risk in the stochastic sense.

So we've got, basically, for those particular actions varying price in some kind of way.

And page 12 is just a graphical representation of what we had for page 11. Some people like numbers; some people like graphs.

I just know, as we drill down a little bit, and this goes back to some of the ideas talked about earlier, and we'll see in other case studies.

So each plan -- and here we've got a graph for plan C -- each plan has a trajectory of carbon dioxide emissions that varies by scenario. So horizontal axis is year, the year of delivery power; the vertical axis million metric tons of carbon dioxide equivalent, okay.

And you can see that, you know, there's a fair amount of uncertainty here driven by the states of the world, what will be the CO2 emissions. And that's, you know, driven by dispatch to a large extent.

So that's something we can measure and represent; the uncertainty in this particular dimension across scenarios.

What's the likelihood of the purple curve versus the red curve. That's not something that we've quantified. That's something we're aware of what we don't know.

Going to the central idea in portfolio theory that we are trying to bring along to electricity planning, that is the idea of trade-offs in some kind of efficient frontier. So, I ask the question, what is the cost of incremental liability.

So we actually chose to represent and state these plans for a reason. That they basically represent stylized end points in some kind of frame.

So if we compare plan B with plan A, well, plan A meets all the mandated requirements. There's a planning reserve margin of 15 to 17 percent, with a one-in-two load. So that implies a particular reliability level. Three outage days in ten years.

What plan B does basically is by adding additional resources, okay, it brings down the outage days from three days in ten years to one day in ten years. There's an incremental cost to those additional resources that do that. And it's about .2 cents per kilowatt hour.

So we're just representing what that tradeoff is. I wanted to look at that, and I think there are different intervenors that look at that and say, it's worth it to do this, or not worth it to do that. But basically we're trying to frame the discussion in terms of quantifying that tradeoff.

If one looks at a different tradeoff,

what if we increase our renewable procurement, okay. Well, this is where one can compare plan C with plan B. So, what happens is, okay, plan B meets the current 20 percent RPS target by 2010, okay, under all scenarios, okay.

Plan B also procures all cost effective renewables. So that's where we use the market supply curve that we discussed earlier, okay. So we actually exceed 20 percent procurement for some scenarios.

Plan C goes beyond that and basically creates additional levels of renewable procurement relative to plan B. And so when we look at 2014, for example, and comparing these two plans, if we increase renewable procurement by 1 percentage point we increase customer costs by about .2 cents per kilowatt hour, and we decrease CO_2 emissions by about 1 million tons.

And so we're trying to quantify those three dimensions. There's, you know, again, the value judgment is which plan does one prefer. But we're trying to provide the evidence for the discussion on that.

And I'd just note again the summary i have in the second dash there that I just described, I've sort of painted it in very broad general terms. Actually results, of course, vary by scenario.

And one important aspect of portfolio theory is diversification, the hedging effect. And we've talked about that a little bit earlier, and we may talk about that again. I'd just note again here's an attempt, we can actually quantify that here.

When we look at plan C there is a hedging effect. We have an incremental cost of about .2 cents per kilowatt hour; risk is reduced, okay. When we look at the 95th percentile, okay, the risk back on page 11 on the right side, we've gone from 3.24 cents per kilowatt hour to 2.13 cents per kilowatt hour.

And so I'd just note that, you know, that's reducing risk by about 33 percent, okay. And here --

COMMISSIONER GEESMAN: That cuts off your analysis after 2016?

DR. STRAUSS: Oh, this is just a particular snapshot for 2014. One has it for each of the years, right. So.

And I'd just note again, you know, here

we're measuring risk in a particular way, not using standard deviation, but looking at the 95th percentile versus an intrinsic case.

And, again, there are a variety of reasons why we operationalized it this way. And, you know, struggle with how to measure an operationalized risk.

COMMISSIONER GEESMAN: And how far out in time did you run that analysis?

DR. STRAUSS: In our long-term plan that we filed with the Public Utilities Commission covers the years 2007 through 2016.

COMMISSIONER GEESMAN: You didn't go beyond that?

DR. STRAUSS: No, not for purposes of the long-term plan filing.

COMMISSIONER GEESMAN: So the hedge value has an unknown or unquantified value in 2017 and beyond?

DR. STRAUSS: We did not quantify it and did not report it. That's right, so --

COMMISSIONER GEESMAN: But it would still be in existence, would it not?

DR. STRAUSS: Absolutely. Absolutely.

COMMISSIONER GEESMAN: Thank you.

DR. STRAUSS: And so if one, you know, again to extrapolate a little bit, if one takes those terminal year costs and projects them forward, you can say here's terminal year cost, I'll project it forward each year, and here's the benefit of the risk reduction. I can project that forward each year.

COMMISSIONER GEESMAN: Of course, if you're assuming a declining slope of your natural gas price, the value of that hedge in the out year probably diminishes --

DR. STRAUSS: Just want to be a little bit careful, because in 2015 and 2016 there is an up-tick. It flattens out and comes back up. So, there's a real question about what's the projection for 2017. But it won't actually might say based upon these curves on page 7, the hedge effect might be greater in 2017 than in 2014. And it might be even greater in 2020, perhaps. But I'm, you know, extrapolating tremendously there.

COMMISSIONER GEESMAN: Sure.

DR. STRAUSS: So I just wanted to conclude with a summary says basically what do we do at PG&E when we do integrated resource planning. And what have we done in our particular long-term plan.

We consider a variety of uncertainties, okay. And we strive to model these uncertainties systematically. Either with scenarios, either probablistically, using whatever is appropriate, feasible, computationally, resource time; recognizing we fail; recognizing we're wrong. Trying to be aware of we don't know what we don't know.

And so the second point is we continuously strive to improve our methodology in our modeling. And recognize that this is a great forum to take away some insight for how to do that. And here's some ideas, you know, that we're working on to make those improvements.

One, I think you alluded earlier, Commissioner Geesman, to our market supply curves. In particular we're trying to refine those renewable supply curves to reflect the various different attributes of different technologies. And that solar is not the same as wind.

Yes, we can look at gigawatt hours and cost, but they come with a variety of different other attributes. And recognizing that their associations and relationships are not perfectly correlated, okay. So that's something we're continually working on.

Improving those modeling relationships among intermittent resources, load, hydro and prices is something we've struggled with for years. And continue to struggle with and continue to work on and look for additional insight today to that.

We've quantified carbon emissions in this analysis. We haven't put an explicit price tag on those in comparing it. And I note again our methodology ends up with a variety of disparate measures which would compare plans. But we haven't integrated it into a single monetary figure, as alluded earlier. And my sense is, yes, there's formal things in multi-attribute utility theory that might suggest how to do that. But, again, it's a big stretch in practice to do that. So we've quantified it.

But as market price signals from carbon develop, one can include, you know, costs for that in the analysis, as well as quantifying it separately, recognizing there are aspects to that that are just are not priced.

Finally, and this goes back to some of

the discussion earlier, with increased reliance on intermittent resources we can measure, its anticipated effect in operations. We have not done that. And we continually struggle to do that. To work with the ISO on how to do that. And looking for insight on how to do that.

I know I participated in some of the PIER workshops on those kinds of issues. But that's something we're really thinking about how to do that on long-term integrated resource planning.

And finally, we've had a fair amount of discussion so far today on other measures for assessing customer cost risk. And other procedures for how to do that. And that's something we continually think about and wrestle with and discuss.

And so these are the kinds of things that we're thinking about, you know, improving and changing and look for great insight from the folks who wrestle with these issues.

So I do appreciate the opportunity to, you know, discuss this with you this morning; and look forward to the discussions the rest of the day. If there are any additional questions at this time.

CHAIRPERSON PFANNENSTIEL: Thank you, Mr. Strauss, for being here and presenting that. The one generic question I have, and it really is similar to the question that Commissioner Byron asked before. How important do you consider transparency in all of this to be? You have a lot of very, it seems to me, explicit criteria, and you're modeling these based on a number of attributes that you're positing.

And so for decisionmakers, don't we need, and doesn't the public need to understand how all these fit together?

DR. STRAUSS: That's a great point and a great question. And so when it comes to transparency in the public process, I think there are several different aspects.

One is for fully informed discussion and decisionmaking at the Commission, at the Public Utilities Commission, among policymakers in the state, among the folks who eventually pay those costs, customers. It's critical to have full disclosure.

Our one concern is that there are other folks, market participants for whom full disclosure actually to market participants does not benefit customers.

And our concern is with the tradeoff of that. Between full disclosure in a public forum to everyone, including market participants, versus, you know, providing the decisionmakers with all the information needed for the public policy decisions, and preserving proprietary information for commercial transactions.

So, when it comes to well, what was the contract price in recent contracts signed, well, that's very commercially sensitive information. And so we strive in our filings to make that balance, recognizing there's a public need to know.

So I don't know if that speaks to the issue, but that's very much where the concern comes from. And I've actually tried or thought about trying recently, how can I quantify that tradeoff between disclosing the information and what harm it might cause customers versus the greater public benefit of disclosing that information.

And I'm sure there are folks at Morgan Stanley and J. Aron and Powerex who can help me with that quantification, but I'm not sure it's in their interest to do so.

COMMISSIONER GEESMAN: I understood from one of the earlier presentations that over a period of time economists feel that prices tend to correlate with costs quite closely. So, this transparency question, isn't there some function of price discovery to be associated with that?

DR. STRAUSS: We're talking now about the sort of micro-structure design of particular markets? I hear that in general. And I understand that general abstract principle. And if one is assuming perfectly competitive markets ten years out, that makes a lot of sense.

But if you look at how energy trading firms on Wall Street and our counterparties behave, while there may be greater benefit in some sense to price transparency, well, that's, you know, the various market microstructure institutions to stimulate that. But that doesn't mean I get to see the counterparty's books and they get to see mine. That hasn't worked out in practice.

So I hear the point, but I just go back to well, the devil's kind of in the details how real markets work, right.

COMMISSIONER GEESMAN: I wanted to turn to one of the things that I think you do know that you don't know. And that is fuel prices out beyond 2016. From a long-term planning standpoint, recognizing that in these long-term procurement contracts that you sign, you're committing your customers to a particular project, a particular technology for a period of time that goes quite a bit beyond 2016.

How do you incorporate the fact that you do know that you don't know what those fuel prices are going to be out beyond 2016?

DR. STRAUSS: Let me give you some stylized ways that we think about it. Whether we've actually quantified it or represented it. One is, right, we know for an operationally dispatchable plant like a combined cycle plant or a steam plant that was built 40 years ago, or a combustion turbine, there's some capital costs. But actually the operating decision is contingent upon the particular circumstances of a particular day, whether that plant runs or not.

And so one sees that as some cost investment, okay. And the benefits of dispatch, well, least-cost dispatch suggests the plant is running when there is some short-term gain to be gotten converting that fuel into electricity.

So, at one extreme one can assume, oh, there's a sunk economic investment with absolutely no benefit coming out, not dispatch at all. That's one possibility.

The other is regardless of market price, that plant fully runs or runs at some particular operational level. That is, take away its dispatchability by assuming it never runs or always runs or it runs at various intermediate levels. That begins to frame some sense of the economic value that plant holds in certain circumstances. So that's one way to begin to think about that.

And, you know, the key element is it's a sunk investment up front; but the optionality is rested at a dispatch on an ongoing basis. And that's why I made the point earlier we're very focused on, if folks are thinking that these gas-fired units are there running all the time, that's not what we're anticipating even today when we look out at 2014, 2016 and beyond.

We're anticipating a fair amount of

operational flexibility. And if one looks at the history of the steam units that have been in existence for the past generation, as basically they get displaced by more thermodynamically efficient units, well, they tend to run less and less. So one can anticipate that, as well, from, you know, the combined cycle plants.

And if you look to see some of the resources we actually procured in our last long-term RFO, you know, there was a strong interest in reciprocating engine technology and in LMS100 technology, which have particular sunk cost characteristics on a per-kilowatt basis, but have extraordinary operating flexibility compared to a baseload operation of, you know, a combined cycle from design ten years ago.

And even if you look at the combined cycles that we looked at, they were designed, as were the requirements, to have at least 300 starts a year.

So that's some ways we try to represent that when we think about the technology. But if your larger point is, you know, gas prices can be wildly -- you know, wild uncertainty and how does that show up for the gas-fired resources, the key is not to assume particular operating patterns for them.

COMMISSIONER GEESMAN: But if we were back in a vertically integrated paradigm, wouldn't your company, as it once did, point to the uncertainty of those fuel cost projections and say that justified a more capital intensive set of technologies, and that the investment ought to be oriented toward capital intensity in order to diminish that fuel price risk?

DR. STRAUSS: And that's what, you know, reflected on the bottom of page 15 when we see basically that incremental cost then is not just incremental capital cost, but overall cost, still associated with these renewable resources, still has a cost risk reduction benefit.

And I think your point earlier is, hmm, is this cost risk reduction benefit perhaps under-estimated by this number, particularly as one goes to a longer time horizon, you know, that's probably true.

COMMISSIONER GEESMAN: Seems to me that in your calculation of that number, you took two or three frames from a 200 frame film and formed a judgment. If you ran it out over the expected life of the plant, I suspect you'd attach quite a bit more hedge value to that investment.

DR. STRAUSS: Sure, and I just want to make sure, you know, the particular frame we're talking about is 2014, and we recognize that. And we're not trying to, you know, make it's a bigger claim than that, but you're absolutely right. It's a full length feature film.

And the key again is to make sure this time the outcome is different from what happened in the energy crisis.

CHAIRPERSON PFANNENSTIEL: You list the four specific criteria that you looked at: reliability, rates, renewables and CO2. How do you think about energy efficiency? Where is that in there? Do you just assume that you have all cost effective energy efficiency already filled in because of programs at the PUC? Or do you somehow model increased levels of energy efficiency?

DR. STRAUSS: Sure. I just want to try to respond to that by distinguishing between the outcome measures here on the bottom of page 10, the four that you mentioned, and energy efficiency, which we're thinking of as a resource, the analogous to the financial asset that was discussed earlier.

And so the particular attributes of that resource, energy efficiency, has particular, you know, reliability, customer rate, consequences on the portfolio along these dimensions, as well as others.

For example, it doesn't require a power plant footprint. And, you know, there's benefit to that. And we recognize that. That's something we're, you know, we're aware of, even if it's not explicitly quantified when one is looking at these four particular measures.

If your question is well, in our long-term plan where does energy efficiency fit in in terms of the levels we're, you know, planning for, I'm not sure that was your question.

CHAIRPERSON PFANNENSTIEL: My question is do you explicitly calculate the benefits. And if not, why not? Where do we see that? Where do we look to see how much energy efficiency would make sense in your plan?

DR. STRAUSS: Sure. And, I think there's no explicit discussion or characterization in the text of, okay, an increment of energy efficiency has this marginal effect on reliability or customer rates or renewable resources or CO_2 emissions.

But from the overall construct of the data that we have looked at and analyzed, you know, if that's the question, we can explicitly, you know, discuss those measures in that way.

I don't know, Osman, if you wanted to add anything to, you know, give them what's out there, what can be done. But, you're right, it's like it's one of those things, we have the raw material to speak to that question. But we haven't put together the five-page, you know, memo responding to that question in a concise way. It's sort of --

CHAIRPERSON PFANNENSTIEL: Well, energy efficiency is, as I remember, the first item in the loading order. So all the utilities have their setup, and agreed that they would add energy efficiency first. And I'm looking to see the demonstration of how you do that.

DR. STRAUSS: Oh, and we did that by considering the loading order, okay. And we looked at the current targets for the goals for energy efficiency, which if I recollect, is something like -- for PG&E it's something like

1200 gigawatt hours --

CHAIRPERSON PFANNENSTIEL: So you took the PUC targets, assumed those and didn't look further?

DR. STRAUSS: That's right. We actually first assessed the feasibility of those targets in terms of technical potential and economic potential. And assessing the technical and economic potential, we said, that's a heroic stretch goal and we're, you know, committed to achieving that. And, you know, that, in itself, was -- and we have some discussion about that in the testimony. So that's how energy efficiency was treated.

But if you're looking to see, hmm, how was it parameterized, you know, levels of less energy efficiency, more energy efficiency, what does it look like, we actually do have market supply curves for energy efficiency in our analysis in terms of the candidate plans A, B, C, you know, the preferred plan we have has a target level of energy efficiency. And it's regardless of whether it's cost effective.

Maybe, Osman, you could speak more to the analysis and that result.

MR. SEZGEN: Yeah, this is Osman Sezgen from PG&E. What -- was by we tied it to the scenarios and depending on the gas price forecast we calculated different levels of energy efficiency, cost effect of energy efficiency.

And then in our preferred plan we met all the targets basically. So you could go to the other plans and see what we assumed for energy efficiency cost effectiveness in different scenarios.

DR. STRAUSS: Any other questions?

CHAIRPERSON PFANNENSTIEL: No.

DR. STRAUSS: Well, I appreciate the opportunity. And one of the things I'll be looking for in the coming presentations today is, you know, having this representation of our analysis and seeing how the other case studies are represented, sort of where the gaps are in our analysis, where the steps for improvement are.

Because if you look at our 2006 plan, compared to what LBL looked at when they saw our 2004 plan, you can see it's quite different. And we've tried to make some real strides in our methodology as we've applied it. And we hope to continue to do that as we have continuing planning endeavors.

So, again, thank you.

COMMISSIONER GEESMAN: I really want to thank you for being here. I found this very illuminating, and I think it's been extremely helpful to us.

DR. STRAUSS: Appreciate it.

(Pause.)

MR. RINGER: Okay, I'd like to thank Robert Anderson from SDG&E for coming up and giving us this presentation this morning.

MR. ANDERSON: Thank you, good morning. I'm Rob Anderson, Director of Resource Planning for SDG&E.

I took a little different tack at these questions, so I'm not going to quite walk through the things that Todd did. But hopefully you'll find it some ideas that we need to ponder as we address where does this overall portfolio analysis really lie.

And one of the first questions as I read basically your questions, was if we're going to take and address this, where in the process should it be addressed. And partly I come to that because by the time the utility gets to doing their resource plan, a large portion of our portfolio has already been defined for us. We're not starting with a clear slate, where we can take and pick from all these and try to find the optimum portfolio.

And what I mean by this are things like state mandates, such as renewable portfolio standards. They'll, in essence, begin to set some limits. My guess is the 20 percent and the 33 percent target weren't set based on any true analysis is that the right optimal mix for California, but rather policymakers decisions that we want to push this technology, so we want to hit certain levels.

So, if we're going to take on a portfolio analysis, and I think someone said this, is it before these constraints or after these constraints. Because that, alone, will drive a lot in a utility's plan.

Next item. We've talked a little bit about the energy action plan, the loading order. That, in a lot of ways, limits what I can do in my resource plan. It drives a lot of what my portfolio will look like. Once again, constraining some things I can do. So do I do my portfolio analysis before that or after that.

And lastly I listed here the once-through cooling limitations. I put this in as just one example of where another state agency or some other body can take a step that might greatly impact our plan, although they were somewhat outside the main energy discussion that mainly takes place between the PUC and the CEC.

So, in my view, a lot of my portfolio is designed by policymakers to begin with. I'm not particularly wanting to go out and do a portfolio analysis and challenge those policymakers if they've decided that is the correct direction for the state.

Now, when we get these policies, some of the targets have been more analytically determined than others. There's a question there about energy efficiency. This is one place where I think the targets are being looked at very analytically. The PUC and others go through every two years, look at what is the cost effective level of energy efficiency, and try to really determine what is the right portion of the portfolio that should be from energy efficiency based on cost/benefit analysis. And then provides that to the utilities. We have adopted those in our plan and included them.

Do we think they're perfect? No. Are they going to be exactly what we'll achieve in the future? No. Do we think we can hit them in the near term until numbers are updated? Yes. So we're willing to plan to those and live with those because we don't see any future risk to our customers doing opposite of that.

The demand response goal. We've got a demand response goal of 5 percent of peak reduction. I think that was thrown out there more as a challenge than anything else. So, once again, if we're going to look at the portfolio, should we be going back and looking at these goals or taking them as a given.

And our renewable targets. One of the things that's causing for us, as you know San Diego had 1 percent renewables when this target came out, and we're trying to hit the 20 percent renewables by 2010.

That's kind of forcing us to take almost any renewable we can get in order to meet that target. Will we end up with the optimal mix of renewables by 2010? Probably not. Or if we do it, it will sure be by luck.

But, once again, are we supposed to get the optimal mix of renewables; or are we supposed to get the policy amount that regulators would like us to get.

COMMISSIONER GEESMAN: You know, Rob, I look at the experience in the RPS so far, 75 out of 80 contracts signed, coming in below the CPUC's market price referent, I think it would be nice to get the optimal mix under your least-cost/best-fit criteria. But 75 out of 80 below the market price referent would seem to me to be pretty good from the customers' perspective.

MR. ANDERSON: From that general perspective. But, once again, you know, Todd -- if it is all wind that comes in, I'm not sure that that's going to be best for customers. Well, we haven't gotten all wind; we've probably gotten about 50 percent wind and 50 percent other technologies. Once again, is it optimal? No. Is it going to some something okay, we can work with? Probably yes.

Once we get the state really policy guidance, then we have certain other constraints that we really need to work with. One of those is the reliability needs.

For San Diego this has been particularly tough nut for us to work on. As most of you know, we are a constrained service area. The vast majority of all of our procurement has been to get new resources built in the load pocket.

We basically, we're running out of the point where transmission capability couldn't meet the load, so we had to get new resources built. We've offered to sign literally any renewable that's willing to build in the load pocket. We've signed them up. That's not going to be enough to meet our reliability needs. That's most of the gas-powered resources we're doing are in the load pocket driven by reliability need.

Secondly, load uncertainty. And this is the one we spent the most time in in our long-term resource plan that we filed with the Commission this year. And in laying this out, we laid out both a basecase, and then a higher and lower case.

We didn't try to make huge distinction as to what caused the high case or what caused the low case. Because from over all our procurement needs what caused it wasn't as important as to what it was. If the higher need occurred because we have stronger economic load growth, we had to react to it literally the same way as if the higher need occurred because as much energy efficiency didn't occur.

Once again, the lower case. If we got more energy efficiency, more demand response, more other things, it just drove things down. So it wasn't critical what was driving the change in load, only how much was load changing and not changing.

And lastly, the commitment term is an area that we're concerned about. As you know, the state's thinking about reopening direct access. We don't particularly want to be out long in the market if they are going to be reopening direct access.

So we're constantly struggling, how much resources do we commit for the long term; how much do we commit for the short term. You know, we've heard talk today if there's a view that gas prices may get much higher in the future, should we be going shorter so we're not locking ourselves into gas resources. Once again, another constraint.

There may be people here, portfolio -- that can tell me exactly how to incorporate that with their models. And I'd love to hear that.

So we have a lot of constraints and a lot of things really driving us. And so from San Diego's perspective, when I look forward, what did I really see. I saw a portfolio that was going to be about 60 percent must-take resources. And when I get to that I'm about 20 percent nuclear, about 10 percent QFs, which are in most part must-take, and I think we're headed to at least 30 percent renewables to meet GHG goals.

I've got a couple combined cycle plants to fill in the rest of it. But the vast majority of everything San Diego's going to need is all going to be peaking resources. So we're looking at resources that are going to be expected to provide very little energy to the system; it's mainly capacity.

I kind of put a note on here, no matter which portfolio we pick, I think we all need to get behind it and make sure it gets done in a timely basis. I think I've seen times when we've all agreed this is the right way to go. By the time it works its way through the process and it's all get picked at, we kind of forgot what it was that we were starting to. I wish I had a good solution to it.

Our filings at the PUC. We've historically laid out a number of different choices, a number of different portfolios, really depending where we were in the process. Coming out of the energy crisis, our very first filing with the utility, we really laid out resource portfolios that really drove a lot about policy choices.

And kind of the analysis we laid out was this generation/transmission, or both, kind of strategy. Something that's still getting played out in San Diego. And we laid out for the Commission what might the world look like in the future if we are forced to strictly add new generation in San Diego. What might the world look like in San Diego if we tried to solve all our reliability needs with just transmission. Or we did a mix of the two.

And we laid that out, various probabilities, distribution curves on the outcomes for customers for that. And we actually got a lot of support from the Commission to basically, you know, address this both strategy. We're going to need both transmission and new generation in San

Diego.

Since the time basically buying into that overall strategy, we've really been working that strategy. Each time we file a resource plan we haven't tried to go back and reestablish that. We've taken that as a given. And looked to then basically implement this overall strategy.

As I said, our current plans are more focused on the load uncertainty that we have in San Diego. And particularly here we've laid out these three scenarios. And by laying them out actually in maybe a bit more simpler way than what you get out of the portfolio theory, we're able to walk people through those scenarios as to what makes sense.

We've come to the conclusion that there's going to be certain paths, certain resource additions that we can make that under just the basecase or expected case may look like maybe we added a resource a year or two early. But because they hedge uncertainty under a number of other scenarios, that it's the right thing to do.

And so by laying out some scenarios, walking people through these scenarios, we're able to lay out that, yes, if we do this the worst thing may have come that we added a resource a couple years early. But by doing this we've covered ourselves for uncertainty with generation additions and for load uncertainty.

And as we've all been seeing, the thing that keeps happening is load forecasts keep getting ratcheted up, not down.

As we get into evaluation of options we will normally do this based on a set of assumptions or a given range of assumptions. And although we could go through and assign a lot of probabilities to each of those and multiple it out, we tend to test each of these major assumptions for what I call, what would it take to change the result kind of analysis.

I find it much more helpful for decisionmakers and other people if I lay out all these probabilities and say, well, this is the answer. Sometimes they look at you strangely. If you say this is a good decision to go this way, all the way up to gas prices being X dollars, it seems to help facilitate the decisionmaking process.

So, part of what we do when we lay out

and do analysis is trying to be able to do it in a way that the decisionmaker gets the amount of information they need. And sometimes being a little more simple in that than complex is very helpful.

So, with that, my only concluding comments I'd like to make is as someone earlier said, a lot of this analysis, what it really does is it doesn't tell us the right answer, but provides us insight. And I think we need to realize that there isn't going to be any one model that is going to dictate and tell us what the exact answer is.

But all of these models, all these different techniques provide us with a little bit of insight to help us figure out what is the right thing to do.

And, none of these also won't protect us from that bad outcome. In assigning probabilities to all these, there's always that one case, that one-in-ten-years going to happen. We saw it last year. No amount of modeling, no amount of analysis is going to really protect us from that.

And the last thing I'd pose for the group, as a whole, is we've talked a lot about uncertainty in gas price, and customers being exposed to that risk. But I think an overall guidance to utilities in general is how much should we have price signals flowing through to customers, and how much should we be hedging customers from seeing those price signals.

Currently the PUC provides us a customer risk tolerance. It's a value we get. We work with the PUC. We actually find it quite useful because it aligns our interest, the Commission's interest, the consumer groups' interest. And we manage the customers price risk within that risk tolerance.

Does it take all the risk out? No. But it does give us some guidance as to how much to hedge and how much to allow prices to flow.

COMMISSIONER GEESMAN: What's the time dimension of that calculation?

MR. ANDERSON: We actually very actively manage it in a two-year timeframe; but we will take hedging, we take hedging steps out as far as five years.

So, for this year we'll be taking certain steps to hedge it out five years. And we step up the percent of the portfolio that's hedged each year; the most active management's in the last two.

COMMISSIONER GEESMAN: But it's not the type of long-term risk tolerance that would help inform you on a long-term procurement basis?

MR. ANDERSON: No, no. It's more given your portfolio, how do you manage it.

You know, one other issue here is we keep talking about, you know, this exposure to natural gas. You know, my question is, if it's not natural gas, what is it, you know.

Nuclear's pretty much, there's not going to be any new nuclear in the state for awhile. We're adding about as much renewables as we can get our hands on. Coal, at least for the near term, has been nosed out.

So, in some ways, we've kind of restricted ourselves to being a state that's relying on natural gas. And if we want to get away from that we may need to go back and look at some of these other policies.

Thank you.

CHAIRPERSON PFANNENSTIEL: Thank you very much, Rob. That was useful.

COMMISSIONER BYRON: If I may, Mr.

Anderson.

MR. ANDERSON: Yes.

COMMISSIONER BYRON: Earlier in your presentation you asked questions about how to do this analysis, whether or not to impose the constraints in your portfolio analysis that the state has mandated.

And I'm not sure I know the answer as to what you did. You did say you went after all the renewables you could get.

MR. ANDERSON: Right. Currently what San Diego does is look at its portfolio after all of those constraints. But really the question I was posing back to you was if the CEC is overall looking at this, should we be looking at it on a statewide basis, without these constraints at first, and then helping use the constraints, or the information we learned from that analysis to help then guide our policymaking going forward.

COMMISSIONER BYRON: Well, I know I would do both. Did you do both kinds of analysis?

MR. ANDERSON: We did not go back and push on the policy guidance from the state already. We took the guidance as a given. So we haven't gone back and said if the state was to relook at that, what renewable percentage would they hit.

COMMISSIONER BYRON: Okay, thank you.

MR. RINGER: Okay, the next two presentations will be the case studies that London Economics has done, and then the Northwest Power and Conservation Council's presentation. And those both tend to be slightly longer, approximately an hour each. So I think this might be a good time to take a short break for lunch.

CHAIRPERSON PFANNENSTIEL: And that's because we don't have a presentation from Southern California Edison?

MR. RINGER: Correct.

CHAIRPERSON PFANNENSTIEL: And why is that? Were they invited to present?

MR. RINGER: They were invited to come here. I think there may be a combination of some miscommunications either internally there or possibly from us. I'm not exactly sure.

CHAIRPERSON PFANNENSTIEL: Perhaps Mr. Alvarez can help us with that?

MR. ALVAREZ: Yeah, I think, Commissioner, I apologize. We can respond with a presentation in terms of how Edison does its resource planning on June 12th.

I think there was a miscommunication for this particular workshop. I was under the impression that you wanted us just to participate in the panel discussion and talk about some of the issues that were going to be discussed later on.

And we had a couple of specific issues that we wanted to bring to your attention.

So, I apologize for that. I'll take the responsibility for that, but --

CHAIRPERSON PFANNENSTIEL: But there will be a later workshop --

MR. ALVAREZ: Yes. And I'll actually file something by June 12th. And I'm available to talk to each of you at your pleasure. So, I apologize. Thank you.

CHAIRPERSON PFANNENSTIEL: Thank you. Then I guess we probably will use this as an opportune time to break for lunch.

Why don't we try and get back here at 1:00.

(Whereupon, at 11:52 a.m., the workshop was adjourned, to reconvene at 1:00 p.m., this same day.)

--o0o--

AFTERNOON SESSION

1:14 p.m.

CHAIRPERSON PFANNENSTIEL: Are we ready to go?

MR. RINGER: Yeah, we're ready.

CHAIRPERSON PFANNENSTIEL: Okay, go ahead.

MR. RINGER: Okay. The next couple of presentations are going to be the case studies that we talked about, starting with the Northwest Power and Conservation Council's fifth power plan in their planning process. And I would very much like to thank Michael Schilmoeller who came down from Portland to give us this presentation.

MR. SCHILMOELLER: Good afternoon. And also with me is Jeff King. Jeff maintains a database of resources for the Council, and is involved in a number of things, such as the region's wind integration study. And I think I'll be deferring to him on any specific questions related to those issues.

There are three areas that we can talk about this morning; and I kind of structured this presentation to be flexible. The first portion of the presentation is about the regional portfolio model and some of the concepts and procedures that we use.

The second has to do with the Council's risk metric. And the third is the discussion of a particular kind of uncertainty, that dealing with carbon risk. And these are pretty much independent and stand-alone. So, depending on the time constraints, I'll check in with Madam Chair from time to time and find out how we're doing on schedule.

So, to begin, the way we think about risk and talk about risk differs a little bit from the way that some other folks do, so I want to define some terms here.

Uncertainty is, by and large, what most people think of in terms of uncertainty, uncertainty in assumptions. A lot of utilities, however, confine themselves to uncertainties that are described by historical distributions. And we look at strategic uncertainty. Or I think I've heard others refer to it as structural uncertainty.

Risk, for us, is not standard deviation. The aspect of risk that we're most interested in is bad outcomes. And that's basically what we're concerned with.

Stochastic analysis and scenario analysis. Again, some utilities, in their IRPs, distinguish between these. And they refer to stochastic analysis, again, as the outcome of the plans based on these historical distributions of key assumptions. and scenario analysis is something completely different that generally doesn't have probabilities associated with it, but comprises or represents these strategic sources of uncertainty.

And we don't do that. We use stochastic analysis to look at different scenarios. And one way that we've characterized that is scenario analysis on steroids. We find that's a lot more productive, looking at radically different futures than looking at, you know, historical variations and assumptions.

And there are probabilities associated with our uncertainties. The conclusion that I've come to is that in valuing options to take various measures, basically you have to assign probabilities. And decisionmakers do assign probabilities, whether they're willing to say that or not.

Two of the ways in which this model really distinguishes itself from a lot of commercial models out there is that we abandon the assumption of perfect foresight.

Most models, to do capacity expansion, are cost minimization models or try to find an expansion sequence of plants that arrives at market equilibrium and prices. But intrinsic in that is the assumption of perfect foresight. And we do not use that.

Instead we use decision criteria. The model uses decision criteria. They're actually built into the modeling process. And depending on what the model sees as the future at that point, it makes decisions. And it's looking at requirements for resources; it's looking at forward curves for electricity and gas price or coal price or aluminum prices. Aluminum prices are relevant to us because we have a large smelter load up in the Pacific Northwest.

And based on that it makes decisions. And very often those decisions are wrong decisions. And so part of what we're trying to do is basically monetize the planning flexibility in the plans that we select.

These are adaptive plans. They adapt to the future in which they find themselves. And, again, I don't know of any commercial models that do that.

We will also construct an efficient frontier. And to do that I need a few more terms here. We distinguish -- we speak of plans and futures. And futures are pretty much what they sound like. Basically what we're doing is characterizing key sources of uncertainty, hydro conditions, loads, fuel prices and so forth. And we're trying to capture hourly variation. Our model is not an hourly dispatch model, but we try to capture the hourly texture of these key sources of uncertainty. And we can get into how that's done in detail later.

And then we speak of plans. And plans are -- and this is also quite different from perhaps what you've seen elsewhere -- the types and amounts of resources, with the earliest be prepared to start construction dates.

These are really options. And when we pay for our options what we're doing is we're paying for the siting and licensing of resources to be available at specific points in the future.

Depending on whether those resources are needed, we pull the trigger on those options.

And at that point we begin construction. And I'll illustrate that in just a second here, what happens during construction. But depending on the future we may have cancellations; we may have deferrals or mothballing; or the plant may go through to completion.

A bit more abstractly. Futures of those things over which we have no control. And in this model that's quite a bit. And plans of those things over which we do have control. Including policies that we might implement for addressing things like cost effectiveness standards for conservation.

So, this is an illustration, just to start making things a little bit more concrete. The plan is tasked by federal statute to come up with a long-term forecast for loads, and a plan of resources over the next 20 years. And we produce these plans every five years.

These dotted lines here are the long-term forecasts for loads in the Pacific Northwest. Across the horizontal axis we have time, out 20 years. Along the vertical access we have energy.

We have this parochial term, average megawatt hours, or average megawatts. And that is actually a measure of energy. And it's as the name suggests, that amount of power applied over, you know, unless you don't specify otherwise, a year, 760 hours. And that results in a given amount of energy. And that is the unit average megawatts.

What we have, these thinner lines are individual futures for our load requirements in the Pacific Northwest. And they vary quite a bit. By and large we try to be consistent with the long-term forecasts for loads, but of course there's seasonality. We also introduce all kinds of dis-equilibriums, excursions from underlying paths, jumps.

One of the things that we're very concerned about are dis-equilibriums in markets that last a year or two or three years until things can readjust.

So there are, in addition to weather variation and that sort of thing, there are jumps and excursions that take us away from sort of the underlying path, if you will, for load forecasts over the 20 years.

This is -- and again, this is about six

different futures. Ultimately we use 750 futures.

And that's one element of the future, if you will. This is a list of the other sources of uncertainty that we explicitly model in the regional portfolio model. We had the conical ones, if you will, load requirements, gas price, hydro generation and forced outage rates.

Of course, we'd be remiss if we didn't include electricity prices. And then we also include aluminum price because of the smelter load that's so significant to our region. We also measure carbon penalty. And we do that using what we call a carbon tax, although we readily recognize that that's a tax is very unlikely, but for the purposes of capturing the economic consequences of carbon penalty, cap-and-trade system, whatever, we think that this is sufficient.

We don't look at the allocation of those kinds of risks among various stakeholders. What we're most concerned about is the perspective of regional ratepayers.

Production tax credits, and green tag values, or I guess what's more commonly referred to now as renewable energy credits. Those are all modeled as stochastic variables.

So, that's futures. Now, plans look kind of like this. We've got six different types of technology here. Combined cycle combustion turbines; single cycle combustion turbines; coal plants; demand respond; wind capacity; integrated gasification combined cycle.

And then across the top of this table we have the years in which construction can begin on each of those types of resources.

And in each row we have the cumulative amount in megawatts of each of those resources that can be added at each point in time.

Let's see, this plan actually is the plan that was adopted by the Council. So, this kind of gives you some idea of where this sort of analysis takes you.

And as you can see, we have quite a bit of wind generation in there. In fact, the amount of wind generation that was eventually added was really constrained by what we felt the region could, or what we felt we could justify the region could accommodate without increases in transmission capacity.

There's also conservation here. And

we're anticipating meeting approximately half of our load with conservation and energy efficiency measures. And that's completely in keeping with what we've done over the last 25 years that the Council's been in business.

There are couple of numbers here that refer to actually a sort of a premium over-market, that the cost effectiveness standard for conservation would meet. We have found that or -- well, I'll get there in a minute -- we found that by actually paying a premium over market price for electricity, using that as our cost effectiveness standard, we can reduce both the cost and the risk of the system.

Conservation, as it turns out, makes actually a very good contribution to reserve margin.

Now, again, depending on the circumstances, these values vary; and will -- I've got a little animation that kind of shows how implementation of this plan varies rather dramatically from future to future. And that includes the conservation. That's not locked in.

We're using the same kind of decision criteria, it's a different decision criteria, but we're basically using a projection of what the cost effectiveness at each point in time should be into the future. The model's making decisions about how much conservation to implement. And then things can change.

And you're probably not terribly interested, but down at the bottom are some of the assumptions that describe the construction lead time for various resources.

Now, to make these plans accommodate their circumstances, we model -- well, of course, we're modeling hourly dispatch into the market. But we're also modeling the response of the construction cycle to changing circumstances. Some resources give you quite a bit more flexibility than others with respect to accommodating changes. And some can do it much less expensively than others.

It turns out that simply the construction cycle lead time is an important factor in determining the risk associated with a given resource.

What we did was we looked at the typical -- this is actually for a combined cycle combustion turbine -- the cash flow over construction period. And during the early part of this construction, this is actually siting and licensing early on, and that's going to be less than 5 percent, well less than 5 percent of the total cost of construction.

And then if we believe that we're going to proceed, then the construction enters sort of its first phase, serious phase, where we break ground and we put in infrastructure, and we put in preliminary contracts for boilers and turbines.

And then there's typically another major decision point in the construction cycle for a power plant. And at that point you're taking delivery of the boiler, you're taking delivery of the turbine and it's beyond that point it really doesn't make any sense to defer construction or cancel the thing. Your best option at that point is to finish it up and try to get as much value out of the plant as possible.

So, what the model's doing is it's following basically this process. And, in fact, the early part of the process is what we're paying for in terms of options. So, each plan actually assumes that this part's been done and paid for. And then we go into an optional construction period. And then a committed construction period.

Now, if there's some adverse event that occurs, the forward curves crash for this type of technology, that sort of thing, and you're in the committed construction period, then, as I say, you just finish things up.

If, however, you're in the middle of the optional construction period, the model can delay, at a cost, of course, the construction of that power plant if you can specify what a maximum delay is. And if it exceeds that, you cancel the plan.

Otherwise, you presumably don't do any construction. You mothball it until the circumstances reverse themselves. And then you finish up the amount of construction that's outstanding. And you proceed with the construction of the power plant.

And this captures something that people in the finance industry refer to as real option value. You're actually costing and valuing planning alternatives. And, again, this turns out to be quite important to the value of various resources.

Okay, so now what we do is we take a

given plan and subject it to a future. Let's think about that plan that I put up just a few minutes ago. We subject that to a specific future, and that provides us with a net present value cost.

And we put that in a bin. And we do the same thing. We expose that one plan to a second future. And we get a net present value cost associated with that. And what we're doing is we are capturing all the forward-going fixed costs, construction, fixed O&M, that sort of thing, and all of the variable costs of existing and new resources.

And we go ahead and we do that now, we expose our single plan to 750 different futures. And when we do that we get a distribution of costs. And what we do is then we take away from this distribution two values. A measure of the central tendency that gives us an idea of, you know, what the likely cost of that plant is. And we use the average cost as our statistic there. Arguably something like the median would make more sense, but.

And then the other value that we take away is our measure of risk. And we call this

TailVaR90, and it is the average of the 10 percent worst outcomes.

So if there are, you know, significant outliers over here, this helps -- this reflects those low probability extreme events. That's one of the things that a measure like TailVaR90 does. It's actually part of a class of risk measures called coherent measures of risk. And I'll get into more of that in the second part of this presentation if folks are interested.

Okay, so we take two values away from this distribution. And we're going to express this distribution associated with this one plan as a point in a two-dimensional space. And the projection of that point on the horizontal axis is the cost -- and here I've got costs increasing off to the right -- the projection on the vertical axis is risk, TailVaR90 risk. And I've got risk increasing as we go up.

Now, if we picked another plan -- you can find a whole host of different plans that have that same amount of risk. And there is, in principle, one or more least-cost plans for that level of risk.

If we vary the level of risk, and now we look at all the plans with that level of risk, there is also a least-cost plan associated with that level. And another level. And we sweep out, through this process, by doing -- taking a sampling of these plans, what we refer to as the feasibility space. I think it's been referred to as an opportunity space.

The other thing I should point out to you is that in the preceding presentation I think the axes were swapped, so don't be confused by that.

But what we're really interested in here is the efficient frontier. And it comprises of it's the risk-constrained least-cost plans. It is the cheapest; it is the least expensive plan at each level of risk.

So that's how we construct that. And actually there are a very large number of points in this space. We have only five or six different resources, but when you then look at when those resources are built, and multiple editions of those resources, you have 10 to the 23rd, roughly, in this particular plan, possible points or plans in this feasibility space.

So we actually use stochastic nonlinear

optimization to help us select these plans. Initially it's completely random, and the optimizer then is doing the work of finding the plans on the efficient frontier.

It's kind of interesting to look at what the plans look like along the efficient frontier. If we look at plans that are closer to the least-cost high-risk end, what we have is basically a plan that relies on the market.

We've got conservation meeting about half of our requirement. We've got some demand response that is valuable to us because actually there's quite a bit more market volatility in prices. But we have quite an exposure to the market.

And if you're risk indifferent that makes a lot of sense because, you know, the argument is that prices equal long-term marginal cost of resources and so forth and so on. And so you just wait for the most efficient actor out there to produce the, you know, least expensive turbine. And eventually you'll avail yourself of that energy.

As we move down, though, we're building resources, wind, coal plant, this IGCC got in there. And this is really the kind of option buildout pattern that the Council eventually adopted. They chose this plan down at the end of the straight-off curve. And we have conservation, coal, wind. We also have combined cycle combustion turbine and a little bit of single cycle combustion turbine.

One of the interesting things about the nature of this is that up here at the least-cost end, all of the resources are over the long pull, typically in the money. They'll cover their costs. When you get down here you're paying a premium, an insurance premium, to make sure that you have the capacity.

And now a significant portion of your resources may no longer cover their costs. And that is the insurance premium that you pay to reduce risk.

So, this is something that I've used to explain kind of what the model is doing internally. What we're looking at is a single plan, and actually this is the plan that the Council adopted, and a single future.

And there's a whole bunch of different graphs here that treat various aspects of the performance of this plant under this future. And I'm just going to step us through them.

The one at the top here is exports, negative values would be imports. The vertical axis is average megawatts of imports and exports. The horizontal axis in all of these is time, and it's the 20-year study horizon that we used.

This one over here is annual loads and generation, including contracts. These dark blue lines, these are the stacks, our resource stacks. The red line are the requirements. And where you see the requirements exceeding the -- where you see the resources exceeding the requirements, you have exports out of the region. And they will exceed generally when market prices deem that it's economic to do so.

These resources are stacked; the blue at the bottom are existing hydro facilities. There's a brown area that runs along here. That's existing thermal. And then at pretty much the top of these things, the top 10 percent or so, then you've got the portfolio that we're actually evaluating. And that's got the additional conservation and the additional wind and so forth.

Over here we've got the average

electricity price. These actually represent three-month averages of electricity price. In this particular future we've got a couple of good-sized excursions here that last a year or so. And during which the average electricity price would get up to about $130 a megawatt hour. Most of the time it's knocking around down about $40 per megawatt hour.

We've got, on this one, natural gas prices. This is in dollars per million Btu. this is pretty tranquil trajectory of natural gas prices. Not too much going on there. We've got our CO2 tax, or our CO2 penalty, and it's just lying on the floor. It's zero in this particular future.

Here we have the buildout schedule. And, again, I've already kind of shown you one of these, so I won't dwell on that. But this actually shows how many average megawatts of buildout we have for the different types of resources.

Down here we've got annual cost. There are actually two sets of bars here. And there's kind of a shorter sequence of bars that represent the capital costs associated with these decisions.

And we're keeping track basically of the buildout that's taking place up here.

And then this big thing in the middle is the net present value.

This one over here actually is a variation of this one that has more detail, but it's also much more confusing. So I won't pull us through that.

Now, this is one future. Here we've got a different future. Notice that the buildout is different. And we've got a $10-a-ton CO2 tax in that one that arrives in about 2016. The peaks in the electricity price have gone away. There's a little bit more activity in gas. Looks like our load is down a little bit; our exports are up. And, let's see, it looks like the single cycles went away there.

There's another one. Now, by holding this button down you get an idea of the amount of strategic uncertainty that these plans are exposed to. This is the 750 futures that this plan was exposed to. And you can see the buildout changes quite radically.

We've got all kinds of different CO2 taxes coming along. We've got some pretty interesting electricity price behavior.

And our hydro variability, of course, is very important to us in the Pacific Northwest. We have about 20,000 average megawatts of energy requirement. And in an average year we get 16,000 average megawatts from our hydro. But that can be anywhere from 12,000 to as much as 20,000 average megawatts. So that's a pretty substantial source of volumetric uncertainty, if you will.

And my boss actually used this model to, you know, take a look at what the regional portfolio model was doing and assure himself that, you know, what was coming out of there made a lot of sense.

You can drill down into any one of these futures and actually look at the decisionmaking process that's behind each one of those resource buildout decisions in each period of the model.

So how is this achieved? Well, depending on your view of computer models, this might be the disappointing part. My training's in mathematics, so I'm more interested in algorithms than the actual type of computer model. The calculation engine is an Excel workbook, it's an Excel worksheet.

And what that worksheet does is it calculates net present value for a given plan under a given future. And it calculates in about a second, a little over a second.

The reason for the choice of the model as an Excel workbook is that as you may or may not know, by and large everything that the Council does is in the public domain. And our real authority, or the Council's real authority stems from the perception that it's a free broker of information. It's critical that everything we do is transparent.

And so we wanted to have a model that we could put into people's hands. They could look at how the model was doing the calculation and assure themselves that there wasn't anything funny going on. So Excel is a pretty good tool for that.

There's an awful lot of visual basic for application behind the model, but again, that's by and large accessible by all the folks that do integrated resource planning.

So this model produces a net present value for a single future and a single plan. Then what we do is we have an add-on. For the last plan that add-on was a crystal ball add-on. And that's how we varied the futures. And that's what gives us our distribution of net present values.

And then we have a stochastic nonlinear optimization program that sits on that. That's also an Excel add-in. And that's what's teasing out this feasibility space and the tradeoff curve, the efficient frontier of the feasibility space.

And, again, what the stochastic optimization is simply doing is it's initially trying to find a least-risk plan. And once it does that, then we fix the level of risk that's a constraint. And then it tries to find the least-cost plan, given that level of risk and so forth. And it sweeps it out.

Now, one of the things that we have been working on, again, actually since the inception of this project we envisioned a meta-model. A model that would actually write these Excel workbooks. Produce an Excel workbook that is completely crystal ball aware, or -- at risk aware, that you can put these things underneath Excel with those add-ins and do the same kind of simulation, yourself. And we call that Olivia.

And Olivia actually helped us produce the first regional portfolio model that was, you know, subsequently developed and became the model that was used to make the recommended plan.

And its value lies in being able to explore different representations. We weren't sure whether it was useful to break the region into different transmission areas and model all that detail; or just have a single region. What the time periods should be that we want to use, whether they're months or years or whatever. And Olivia allowed us to explore that.

Now, we're not quite ready for primetime now, but I have an -- am accountable to have Olivia classes by the end of this year. And at that point we hope to be able to put this kind of tool into the hands of utilities or anybody, really, who wants to explore this kind of portfolio evaluation and risk evaluation.

Okay, so, that's the first part of the presentation. The next one is on the Council risk metric. Madam Chair, how are we doing? Would you like me to proceed?

CHAIRPERSON PFANNENSTIEL: Yes, please.

MR. SCHILMOELLER: Okay. So there are obviously a whole host of different risk measures that one can and arguably should consider. And, in fact, what we did in our analysis is we went ahead and computed all of these values for each one of those distributions. They include things like standard deviation, VAR, quantiles, loss of load probability, resource load balance, cost variation.

One of the things, of course, the net present value doesn't capture at all is rate volatility, the change in cost from year to year. So we were very careful to make sure that we looked at that independently.

The other thing is are the conventional engineering criteria for reliability, loss of load probability and unserved energy. And so we have other models that we brought in to evaluate the plans along the efficient frontier.

And as it turns out, all of the plans along the efficient frontier met our loss of load probability criteria. In our particular situation it turns out that the economic criteria for risk management is more sensitive than the engineering criteria. When you start to run into the situation where you're actually curtailing loads, that's a very expensive regime to be in.

Again, what we arrived at was this

TailVaR90 risk, the average of the 10 percent orders to outcomes. And there were several things that kind of drove us to that.

The consensus was that we didn't really care that much about how predictable outcomes were, the kind of thing that a standard deviation might measure. What we were really more interested in again were the bad outcomes. And if we were trying to value options to manage that kind of risk, then we want to make sure that we're evaluating the changes to the bad tail, not the good tail or the distribution.

The other reason for doing this, though, is to a certain extent it was required by statute. The Council is required to recommend a safe, reliable and efficient plan. And we've always interpreted efficient to mean economically efficient. And if your objective function is economic efficiency, it pretty much stands to reason net present value is what you want to do. And the bad outcomes are something like a measurement of the bad tail of that distribution.

TailVaR90 actually belongs to a class of measures, risk measures called coherent measures of risk. And I think the seminal paper was released by Artzner and others in 1999. And what they were doing is they were concerned about some of the shortcomings associated with standard deviation and VaR, that those in the banking industry, the risk management industry, insurance companies and so forth, had identified. They knew there were problems with those kinds of risk measures.

And what they came up with was -- okay, I think this is the only equation this afternoon, I apologize -- but some people find comfort in knowing that these things can be written down -- sub-additivity. And these little rows here, those are the risk measure; the x's and y's, those are stochastic variables associated with the outcomes of the distributions.

And what this says is basically that a merger cannot increase risk. This is basically -- this basically says that diversity matters to us. And quantile measures like VaR or the 90th percentile can be shown not to capture that. They don't reflect diversity.

Monotonicity says basically that if a plan, if every outcome associated with a plan is better than an alternative plan, it cannot be considered riskier than the other plan. And standard deviation violates this. Obviously you can have a much more predictable outcome by building lots and lots of resources, but in every single future you're worse off because it's so expensive.

So that's what this is. There are two more here. And these are most applicable to situations where your risk measure is basically expressed in the same units as the outcome, itself.

For example, monetary loss, or in our case, net present value, cost; a risk measure is expressed in terms of net present value dollars, as are the elements described by the distribution. But that isn't true of all distributions. For example, if you're talking about loss of load probability, or unserved energy, you can't really use these two.

But this is basically relationship that states what happens at the extreme where precisely there is no diversity. And this little equation down here basically says that if you add a certain cost to a distribution, that it will move that risk measure by an equal amount.

Okay. And, again, I think I've already mentioned this. Standard deviation, VaR, loss of load probability, any quantile measures are not coherent.

Examples of coherent measure, TailVaR90. Also there's one used in the risk industry called expected loss; it's the average loss exceeding some threshold. That can be shown to be coherent. And then we've got things like unserved energy, which are both sub-additive and monotonic. But they don't subscribe to the other two restrictions.

Now, at this point I can skip over about a dozen slides if you will take it as a matter of faith that, in fact, the statements that I made on the preceding slide are true. The rest of these, the next dozen slides basically show, you know, why using a mean and a standard deviation can get you into trouble, especially if you're concerned about bad outcomes.

So, if that's okay, and loss of load probability is not coherent. Let's see here, VaR is not coherent. Okay. Wasn't that easy? Okay. You really didn't want to see those. There were actually a lot of equations on those.

So, the last part of this presentation addresses carbon risk, in part, carbon penalty. Madam Chair, how are we doing? Is that --

CHAIRPERSON PFANNENSTIEL: I think we're doing fine, thanks.

MR. SCHILMOELLER: Okay. In mid-2003 we convened in the advisory committee to find out what the experts thought regarding the likelihood of a carbon penalty, the timing of that penalty. This is something -- advisory committees are something that we use to ferret out a lot of the uncertainty distributions that we use for these scenarios, if you will, these futures. We have experts come in; this is all in the public domain; we bring in experts from around the country. David Vidaver has helped us out with some of these.

And we asked this particular advisory committee, you know, what can you tell us about the likely distribution of carbon penalty. There wasn't a whole lot. The only thing they seemed to be able to agree to is that if there was going to be a change, there was going to be an imposition of some sort of carbon penalty, it would probably be in a year following an election year, U.S.

election. So, we incorporated that in our analysis.

Ultimately we used something called thresholding, which the gentleman from San Diego Gas and Electric referred to. And I'll explain in a second how that worked for us.

This is basically what our CO2 penalty futures look like. They're -- the timing of the imposition of the penalty is a random variable. There is actually a one-third probability that there will be no imposition of any kind of carbon tax in the future. And the level is a random variable.

Now, up through, I think it's September 2008, the largest value that we can achieve -- no, no, between now and 2008 we assume no carbon penalty. And then I think between 2008 and 2016, again this is the horizontal axis' time here, we can have up to, I think, a $15 per ton carbon penalty; and beyond that it can go up to $30 a ton.

And if we run across all 750 futures this is the kind of probability distribution we get over time. These are deciles. So, this is the maximum level in any of the quarters that the carbon penalty reached. And so that reflects kind of this artificial ceiling on the carbon penalty.

And then this one is 90 percent; and this one's 80 percent. And as you can see here, the last one that you see down here is associated with 40 percent. So, again, nearly a third of them were -- a third of the futures had no carbon penalty.

The average is illustrated by this black line. And that was actually lower than PacifiCorp's assumed level of carbon penalty in their basecase. So we felt that we were pretty comfortable with this distribution.

I guess this would be a good point to introduce the thresholding. What we did was we actually started out initially with fairly high levels of CO2 tax penalty, high probabilities. And what we discovered is we could dial those back, reduce those probabilities, reduce the penalties and not have any impact on the plans along the efficient frontier down to some point.

And then what we did was we adopted that sort of the floor on that regime where we weren't changing the plan. We adopted the threshold value. And what that permitted us to do is basically arrive at a plan that was credible with the largest possible audience.

People who thought that, you know, there's much higher probability of CO_2 tax, or it's going to be -- the penalty's going to be much larger. There really wasn't anything to offer them. They had no traction with that argument because it really didn't change the plan.

Okay. Now, there are a number of -- lots of things related to carbon risk that this model's capturing. You know, clearly its load requirements change and hydrogeneration changes the amount of carbon that's produced will change. There are these other elements, green tag value and production tax credits that are more or less independent of everything else we've talked about up to this point. But are not necessarily -- especially this last one, independent assumptions regarding carbon risk.

And we'll talk first about the green tag credit, or the renewable energy credit. The thinking was that that sort of thing, because these credits are actually traded outside of the energy industry, that they probably have a life that extends beyond the imposition of a carbon penalty.

And the representation, the uncertainty of these green tag credits, was probably the least sophisticated of any of those that we did. We used, you know, geometric -- motion for aluminum prices and so forth. But for this cut we just used straight lines.

So we've got, you know, straight lines distributed. They start out here; they bunch around $3 to $4 a megawatt hour; and they extend out to anywhere from $1 to about $8 by the end of the study time period.

For the production tax credits, we went into quite a bit more detail. The production tax credits arguably are a way of internalizing external costs. And if you impose a carbon penalty some of the support argument for production tax credits is removed. And they're, of course, the product of a political process, so, you know, irrespective of whether we have that penalty or not, there's a chance that it will go away anyway. Or that actually well beyond the time when say wind is cost effective with the market, they'll last, they'll hang around.

So, we had a stochastic variable that

described how far out into the future we expected production tax credits to remain. And it peaked right around the point where we thought that wind generation and market prices would cross.

And then there was another aspect of this. We didn't think that production tax credits would remain if carbon penalties were exceptionally high. And so what we did was introduced a function of -- on the horizontal axis here we've got carbon tax; and on the vertical axis this is the real levelized dollars per megawatt hour associated with a production tax credit.

And as you can see, it stays at the assumed level of about $9.90 until we get to about 50 percent of the level that we believe the production tax credit corresponds to in terms of a carbon tax. And then it falls off and is completely gone at the point where that is -- exceeds that point by 50 percent.

Again, this is very arbitrary. But at least it addressed some of the concerns that people had about the possibility that, you know, we'd effectively be giving renewables kind of a double credit here.

And this actually represents the combined effect of the production tax credit -- I'm sorry, the horizontal axis is the CO_2 tax; the vertical axis is now dollars per ton of CO_2. And this is the net effect of both the carbon penalty and the production tax credit.

So when the carbon penalty's quite low, you still have the effect of the production tax credit. It increases to the point where you start now coming back on the, you know, dialing back on the production tax credit until it's completely gone. And then the support is entirely through the carbon penalty.

And this is something I think I'll skip. This is basically a probablistic description of what's happening to that production tax credit across all the futures over time.

So, conclusions. First of all, I think it's important to realize that there are optimal resource choices, even when the future is uncertain. Even if you have no knowledge of the future there are optimal choices that can be made. And that's part of what this model's attempting to capture.

Decisionmakers change course based on

the outcome, you know, of their circumstances. And this is more akin to military strategy. A military leader needs to have all sorts of different plans; those plans cost money. And then you go into the situation and you find that something has changed.

Well, if you've done a good job of developing your options and your plans, then you have something to implement. But obviously you have to, in addition to having those options, you have to cost those strategies.

And then finally to value the exit strategies and contingency options, decisionmakers need to assign probabilities to those futures. There's simply no other way that I know of, of assigning value to something that is an option, other than by assigning some sort of explicit probability.

And then there's a lot more that I could say about how individual utilities might implement this and so forth. But that concludes my presentation. Questions?

CHAIRPERSON PFANNENSTIEL: Thank you very much. Real interesting presentation. And you say the time is coming up soon when it will be available to others?

MR. SCHILMOELLER: That's our bet, yes. Now, in the spirit of full disclosure, I have to say that I've gone before the Council twice already to ask for more time. It's been postponed a couple of times, but, yeah, we're shooting for this December to have those classes.

CHAIRPERSON PFANNENSTIEL: That happens. Questions? Commissioner Geesman.

COMMISSIONER GEESMAN: I wonder what weight you attach to transparency in terms of making your model available to others. That seems to be a little bit directly contrary to the California utility philosophy.

Certainly you must have similar considerations you have to weigh as our utilities. What's your thinking there?

MR. SCHILMOELLER: Well, I can't really speak to the California utility situation. Yeah, certainly the credibility of our work hangs in a very sensitive fashion on the transparencies.

We do work with, and Jeff might speak more to this in detail, we do work with the individual utilities quite closely using confidentiality agreements, for example, to acquire information about plans for wind generation and that sort of thing. And those seem to work well for us.

We have a good working relationship both with the utilities and with the regulatory agencies.

Is that responsive?

COMMISSIONER GEESMAN: Yeah.

CHAIRPERSON PFANNENSTIEL: Other questions? Yes.

DR. STRAUSS: This is Todd Strauss, PG&E. I just wanted to follow up on the confidentiality. As I understand the role that the Northwest Planning -- the Council has, and I agree that transparency, particularly if I see the analogous body in California being the Energy Commission. And I can see, you know, transparency of the analyses and the results associated with the Commission being really valuable.

And I'd just note that the confidentiality agreement being described is between the utilities with market participants, along with the planning entity.

So, you know, I definitely see the role for transparency in the planning process. The role of utility in California, in the California Public Utilities Commission framework, is to do planning, but also to do procurement. And I don't believe the Council executes any transactions.

So I just want to make sure that the confidentiality is appropriately placed with the appropriate roles.

CHAIRPERSON PFANNENSTIEL: Thank you. Other? Next one, thank you, Mike.

MR. RINGER: For the people who are here I'd like to note that there are extra copies of the previous utility presentations out front now. And those will be posted by tomorrow, as well, on our website.

Our next presentation is going to be a continuation of caste studies that our subcontractor, London Economics, has done. In particular, three case studies will be presented. And I apologize in advance.

Dr. Serkan Bahceci.

DR. BAHCECI: Thank you very much. I would like to -- I will try to be as fast as I can, but before starting, and I'm going to go over the outline a little bit, but just in defense of MPT, modern portfolio theory, the way I see it, it's requires to look at the return and risk at the same time. And that's what MPT is all about.

What kind of returns or metrics be defined. Is it just standard deviation? Of course not. It's just a textbook case; it just the one you see on the second page of any basic finance book is what the standard deviation is used for.

But beyond that, it can come up with any return or any risk metric, and MPT still applies. That, just in the defense of the basic theory of it.

I will again try to go very quickly over the three cases; and then spend a little bit more time on the very last section of my presentation, which is the cross-cutting issues. And hopefully that's going to be a little bit more entertaining. And, at any point, please stop me and ask questions wherever you see fit.

The first one is Ontario Power Authority, which is recently established in 2004, facing a shortage in the province of Ontario in Canada. The markets were deregulated in 1998 and the government introduced a electricity price cap in 2002 after some public outcry. And at the same time, more or less at the same time, they decided to phase out coal-fired generation, which clearly, as you can guess, led to a huge under-investment, in their own words, in -- energy boards. Own words, they need 25,000 megawatts of new generation by 2020.

So in 2004, facing that crisis, they created OPA, Ontario Energy Board, the forecast demand and in case of generation resources. At the same time they conduct independent planning and promote cleaner energy and so on and so forth.

Basically what they do is every year they publish integrated power system plan, IPSP. And IPSP is used, it provides the roadmap for the market (inaudible) Ontario, in their medium- and long-term procurement.

It's a supply mix assessment; and it commands what supply mix should look like for the next 20 years. It's used as a basis for future RFPs and RFOs issued by the OAB. So it has some strict implications. In that sense I think it's very important that it relates to CEC and the IEPR process.

The supply mix assessment is done by constructing several portfolios that balance supply and demand, given the required reserves, subject to specific constraints and objectives. When we say constraint and objectives, clearly there is some politics into it, the public choice, how much of renewables, how much of environmentally friendly resource do we want. And so on and so forth.

But the idea, the target is to get as close as possible to the efficient frontier. And talking about that, going back to the theory, efficient frontiers, they are, except the Northwest, sorry, they are not very easy to capture. Especially in the long term analysis.

It's when something that affects the market fundamentally changes, then you need to go back to the drawing board, recalculate everything, all the expectations. So it's in theory, yeah, we do all the pictures, it's a very good looking picture. It's very informative, very pedagogical. But in practice it's impossible to capture.

So in practice, even in the finance world where it's very very advanced, and they are looking from time to time in a short time period, they try to get as close as possible to the efficient frontier, not on the efficient frontier.

Unless we are talking about the risk-free asset.

Anyway, so that's the target of OPA IPSP supply mix assessment.

The process, I will go over a little bit further, but the process is a little bit more qualitative rather than quantitative, when it especially comes to the risk and risk assessments.

What do I mean by that? They define five scenarios, or five futures or five state of the world that they think captures more or less, in terms of direction-wise, what the future is going to look like. And these are the details of those five scenarios.

Scenario 1, it's I think the most optimistic one. All the expected procurements happen; there are new renewables; conservation is happening; and out-of-province purchases are also materializing. So everyone is happy.

Scenario 4, I believe, is the pessimistic one and so on. But the important point is not the scenarios, but the important point for our purposes here is this is a qualitative choice. You need to, at least at some point, the analysis should make this choice, should define in such assumptions that the future is going to look like. And what kind of cases are we trying to look at.

In one hand we can have 750 futures or scenarios. In the other hand, in the OPA's case, they considered only five scenarios. How detailed do you want to define a scenario, once again. It has pros and cons. You will have a lot of -- if you have too many scenarios, but at the same time it's going to take a lot of resources and probably (inaudible) or something in that sort.

Once again, I'm showing the table just for illustrative purposes. For each scenario what they actually did is they considered, they looked at two portfolios. For scenario 1, for instance, we have portfolio 1A and 1B. And the rows in that table they show the categories that portfolios might differ from each other.

1A and 1B differs significantly in gas and oil capacity, and then nuclear capacity, just to make the supply/demand balance.

So the moral of the story is they are directional. They are not trying to come up with the actual optimal portfolio, but they are directional. Which direction should we go.

If you ask me, probably they should have a little bit more choices here. But they, I guess for the feasibility of the study purposes, they picked only two portfolios for each scenario.

And this is what the -- yeah, please.

DR. STRAUSS: Sure, just a question to clarify that, trying to see how that compares with the table I presented this morning. You're saying two portfolios for each scenario. So was the construction of portfolio described as a contingent strategy depending on how the particular scenario unfolded?

DR. BAHCECI: Yeah, that's -- they are looking at for the next 20 years, and every year each, they actually specify what each portfolio is going to look like. So the evolution of all those portfolios are defined.

What I am showing here is the ultimate end results. It's a little more complicated than this. Again, this is just illustrative. Probably it's one of the --

COMMISSIONER GEESMAN: Well, going forward, are they fully deregulated? Or do they have some utility-owned generation in their future supply mix, as well?

DR. BAHCECI: They have some regulated

generation.

COMMISSIONER GEESMAN: So they're not entirely reliant on merchant --

DR. BAHCECI: No, no. That's also, I think, within the scenario descriptions, but I don't think any scenario assumes a full deregulation of generation.

So this is what the basic result look like. And I'm skipping how they do it, but they use a least-cost dispatch model, dispatching for all the years for the 20-year period. And also a financial model to calculate this, meaning some assumptions of the cost structures.

So, portfolio 1A and 1B; clearly there are others. But just if we look at these, once again for illustration, are compared against each other according to their total costs. And the total costs can also be divided into its components.

This one shows that portfolio 1A is a little bit lower in terms of costs. And that cost is the net present value of annual costs, given the 20-year stream of estimated revenue requirements.

At this point, which is not in the

slide, but I should add, given the discussion in the morning, that they use a 5 percent discount rate, which is constant. Which they say is based on the Bank of Canada -- rate. Which is that a nice measure for the discount rate? I'm not sure. That's once again, some detail to be agreed on.

But what it does is a 5 percent annual rate, and we are looking at a 20-year time span, it clearly lowers the weight for the 20th year to a really low number. Is that a good way to go or not? Once again we need to sit down and decide on. I don't think there is a technical way or a theoretical way to answer that question.

When it comes to risk, this is once again from their study, they say the risk is measured systematically. And they look at various risk factors, the -- ones, the usual candidates. Fuel prices, technology, and when I say technology, it's the marginal cost reduction of new and old years. So if we are talking about a new unit, how efficient that's going to be; if we are talking about an old unit, can they improve upon whatever is happening in the past. You need to make some assumptions or define a probable distribution function of those.

Generator availability, which is more or less you can assume that trend; in some cases it might be choice. So we should be a bit careful. Load growth and weather, which is highly correlated with load growth and so on.

And they ran Monte Carlo simulations, and annual time horizon for each of the 20 years. They defined specific probable to distribution functions for each of the risk factors, which clearly are big assumptions on their own.

For some of them they try to provide facts by just looking at the historical data that let's say a load normal distribution we can use for the coal price. But in some cases, they just make assumptions and probably they all really depend on the normal distribution. Just putting impacts on the central limit therein. But I'm not sure, once again, if that's also a valid assumption or not.

So given that risk analysis, they did present the result. The previous picture we did not have any variations on it. So the result of the previous pictures are just those two black points, which is the total cost; the deterministic average what followed in the dispatch model.

But at the same time the lines show the distribution of the total cost of total required revenues for each portfolio. And as you can see, they are skewed towards lower end. So, just from the financial perspective, this is what they present in their study to the decisionmakers, to the public.

But then the decision is actually a little bit more complicated beyond the financial aspect, the return and the risk that was just presented. There are also environmental aspects of it; how costly one portfolio is in terms of CO2 emissions. How costly is it in terms of the environmental impact. How costly is it in terms of the inter-province transactions.

So, when given the results, OPA -- the result section in the IPSP is actually really long; it takes quite some time -- I mean it's not just one page, when I say it's really long. It's not just a bunch of numbers. It's a discussion of each portfolio in detail in probably all of the aspects that they consider. So, bottomline is political consideration impacts, the risk/return analysis.

But we will see it when we speak about

the others. But another drawback of OPA's approach is they do not try to tie the financial results with the others. They don't try to monetize or measure the environmental impacts in a sense which is measurable to the total cost. They just leave it like that in the form so that the decisionmakers can make a choice on it. That's the nice thing about, I think, being a technocrat or an economist, so that the politicians can make those decisions for you.

When we move on to the -- are there any questions? As I said before, just please feel free to stop me at any point.

When we move on to PacifiCorp, which is, I believe, a little bit more familiar with us, it has two subsidies -- it's a vertically integrated regulated utility -- Rocky Mountain Power; it operates in Utah, Idaho and Wyoming. And Pacific Power, the other subsidy, operates in northern California, Oregon and Washington.

They satisfy the load obligation to their own generation; they own some plants; and they also have purchase power. And every two years they develop a 20-year plan and find the least-cost alternatives.

In this case we are studying the 2005 plan. But I need to tell you that very recently they published a 2007 plan, as well.

We have a very important point here, and I need to relate this back to Commissioner Geesman's comment from the morning about the moral hazard.

PacifiCorp is a regulated utility, so at least on theory they have a rate of return defined for them by the regulators. And they can transfer all the cost to the ratepayers. In that sense, at least once again on theory, they are indifferent of what the cost of procurement is going to be, which creates a moral hazard issue.

If the utility, which is indifferent, if you believe in that, if the utility was just indifferent in this planning, is conducting this study, then clearly they will be considering some other aspects rather than the minimizing costs or other categories that ratepayers might value a little bit more.

So, it is not necessarily aligned with the ratepayers' objective function. That's what I'm trying to say here. PacifiCorp, a utility completely regulated, vertically integrated --

conducting the plan study on its own without enough transparency. But we'll talk about that.

Their return metric is similar to the return metric of the OPA study. That's the net present value of revenue requirements. They constructed the portfolios using supply side resources, including distributed generation.

And I'm going to stop here a little bit and talk about that. Because increases the amount of uncertainty they face significantly. Distributed generation, I'm sure everyone knows, but I'm going to define it. It's the usually small-scale, small-capacity resources owned by consumers, the example is an industrial plant, for their own use.

And when those resources go off for some reason, either maintenance or forced outage, then at that point the consumer comes back to the utility and asks for the electricity.

So, PacifiCorp or the utility does not control the distributed generation resources. But they face the probability of at some point the consumer might come and ask for an extra load, extra electricity at that point. And it's not their choice; it's completely random to them.

They can create some incentives, but that's about it.

So that adds another layer on what they do on the uncertainty that they face. The demand side resources is a little bit easier to classify. Class 1 resources are fully dispatchable. Class 2 resources, that's the demand reduction. And class 3 resources is creating incentives to shift load from peak to offpeak periods.

They also use market transactions. Of course, that's a big item. And the important point is difference from the others of PacifiCorp studies. They start with a reference portfolio, which is the least-cost portfolio.

And that reference portfolio is used as a benchmark for their RFP bid appraisals. And the other portfolio combinations are measured and compared with the reference portfolio. And at the same time, the others are created by just adding and subtracting components or generating assets to the reference portfolio. So in that sense, it's easier to look at a huge alternative space. But it restricts the choice of portfolios that can be considered because we start with various -- and well established reference points.

And I'm going to tell that, that creates some problems, or at least it created some problems for PacifiCorp after the 2005 study.

I personally would like data identification of the two risk categories. Many people talked about that, but they are classified risk into three categories. There's stochastic risk, which is defined over and over again as the changes in the variables that underlying probable distribution functions are known and same and constant, so it's easy to draw either a simulation or do a stochastic study.

Scenario risk is a little bit different. That covers changes, structural changes that cause large and consistent departure from the mean. And the example is the change in gas prices, or future possible changes in CO2 emission targets and so on.

Some of those scenario risk components can be stochastic, can be -- when I say stochastic, not controlled by an economic agent, either an institution or government. The gas prices, although some people might argue that it's controlled by some people, but clearly not anyone in the North America. So we can assume that it's an external risk.

But the CO_2 emissions target is a choice variable. So we should be a little bit careful when we say a change; something, some variable that creates a fundamental structural change in the variables. What's a choice variable, what changes we are creating on ourselves, and what changes are just the nature of the world. There's a nuance there.

And the final, the paradigm risk is completely choice variables. It's changes to the rule of the game. Examples are formation of an RTO, deregulation, some of the states that they are in business, or federal imposition of renewable portfolio standards, or something of that sort.

For stochastic risk, they use Monte Carlo simulations or variations of it. And the scenario and paradigm risks are examined through stress testing.

The important point is as the OPA studied they looked at a multi-dimensional results page. They have the present value of the revenue requirements, capital costs, emissions, market purchases, market sales, so on and so forth, as different categories in their results.

But they created a scorecard. They gave numbers, numerical values to each of them so that the results can be summarized in a single measure, single metric with -- I mean, clearly when you summarize something you lose some information. But it's easier to read; it's easier to look at.

The reference portfolio and all the other data that they considered are created with input from the public. And analysis was performed in technical workshops, which are mainly public. But in the end, especially after 2005 study, there was a huge discussion, especially from the states, about how relevant the reference portfolio is; should they just rest attempts after the least-cost, financial least-cost portfolio, or should they go with the higher environmental standards, higher renewable portion portfolio.

So some states objected to that. And that postponed the RFP process a little bit. But, as I said, before, PacifiCorp just seeks to recover those increased costs from the states who are responsible, who ar objecting the reference portfolio, objecting the outcome because in the end they have -- in a nutshell, if a state wants clean energy they should -- or a bunch of ratepayers, or a public prefers to go with a cleaner energy portion, they should pay for it. That's what PacifiCorp said.

And finally, the last of my case studies that I'm going to go over is a broader one. It's a Canadian transmission and generation company. And mostly operating in deregulated markets. And it's conducting its strategy planning.

So they are not looking at it from the ratepayers' perspective. They are just looking at it from their own. Just to maximize the return to the shareholders' perspective. And trying to come up with an idea.

So, the alternative space for them to consider is a lot broader. The asset structure, in the long term, it also determines the corporate strategy. And when I say alternatives, they considered either continue as a generation and transmission company, as they are today. Or becoming a vertically integrated electricity utility. Or to go overseas and buy, purchase, procure international assets.

I'm going to move on. So this is how they are looking at it. The portfolios that they considered in their long-term planning. The minimum disturbance portfolio is, as the name suggests, it evolves through time, but all the assets, all the retiring assets are replaced by similar types. So very very minimum disturbance to whatever they are doing today.

And we have a continental generation company portfolio which says they should buy, or the case that they buy assets from overseas markets. I'm sorry, the North American markets, including U.S., which they have minimal presence at the time, and the global generation company is, they are going overseas. And they also looked at the western electric hybrid and gas hybrid, either they analyzed the cases to become regulated utilities.

The important slide here, I believe, is this one. In defining their scenarios or futures or the states of the world, they only defined three of them. And they bundled a bunch of categories with each other. From their own terminology they have the moderate scenario, the optimistic scenario, which they called global economic strength, or the pessimistic scenario from their perspective, which they call the global economic weakness.

And for each one they make assumptions about those categories, including volatility, price volatility, gas prices, coal prices, probable and specific ties, siting flexibility and so on and so forth.

So what I'm trying to show you is we have ten categories here. And for each category we can make different assumptions. So the alternatives actually, in terms of scenarios, is limitless. We can make up as many scenarios as we'd like here. It's really really a vast space problem, ten to the 23s is not a bad assumption estimate.

This is regionally a distance unmeasurable categories how they come up with those three scenarios. The load index is not actually -- it looks like they are parallel, but they are not. The slopes are a little bit different.

Siting flexibility, they made up some assumptions on how that affects the energy price in the markets that they're active. Gas price index, coal price index are all based on some stochastic and some qualitative assumptions.

So this is how they did it. For each of the portfolios they established and forecasted the portfolio return; that's in terms of profits, a measure of profits.

After that, then -- after step one, they have a return for each year for each of the portfolios. And they set up and run and test the regression models on it. What key drivers actually explain those return series for each portfolio. So they came up with regression equations; and after tests, they believe that it explains it enough, to a certain degree.

And then to capture the unidentified variables, they bootstrapped the regression equations to get the upper and lower estimates of the coefficients. And then derived the current state of assumptions of the key drivers, as the previous slide showed. Calculate these effects on regressions on exploratory variables. Calculate the returns; forecast the values of weakness and strength returns. And they got three series for each portfolio showing the return of the portfolio for moderate, weakness and strength scenarios, after all those steps.

So this is what the result looked like.

the rate of return is the discounted average between 2006 and 2016. And on the X axis we have the volatility of return, which is the historical return. They did not estimate volatility of the future returns. They didn't -- well, that's an estimate. The average of the returns historically is an estimate. But they did not conduct any complicated one.

And there are three points for each portfolio on that graph. The mid one is what the return should be under the modern scenario. The highest point of the arrow shows what the return should be for the strength scenario, their optimistic scenario. And the other one shows what's going to happen under the weakness scenario.

So, if you look at it a little bit carefully, it defines an efficient frontier. At least without, as I said before, we don't know where the efficient frontier is, but we can, just by looking at this, say that minimum disturbance and continental generation are inefficient. They cannot be on the frontier.

Western Electric Hybrid and Global Genco seems to be, one is high risk, high return; the other one is low risk, low return. Western gas hybrid is also a lot more safer, but it also can be on the efficient frontier.

So, what they got from this point is, as I said, not the actual portfolios, asset by asset, what to do, what to buy at each year. But it's a lot more directional. And they said, well, okay, Western Electric Hybrid, which is good news for our friends here, it can be efficient. It can, given the rate of return that you want to -- rate of risk that you want to face, it gives a higher expected return.

At the same time, Global Genco seems to be bringing a lot of higher expected return than the others. So they considered to go with a combination of the two. Moving towards both buying global assets and at the same time, trying to build up their existence as a utility in the Western Electric Hybrid.

This slide is just a summary of the data approaches to this portfolio analysis for all three case studies. And in view of the time constraint I'm going to skip this, but we can always come back.

And what did we learn from this. First

of all, the scope and objective of the analysis must be defined carefully. And I will delve into it. There are different approaches on how to conduct the analysis.

So if you tell three different utilities to conduct the analysis we will come up with at least three different studies. And we cannot usually say which one is better than the other ones. So there should be some consistency if we want to compare, if we want to look at it from an integrated statewide perspective.

Political considerations are important. And they should be measured somehow. They should be presented as something comparable to the financial results. Otherwise there is going to be a lot of discussion and a consensus is going to be hard to come by.

And scenario risk and stochastic risk must be handled separately. And there are going to be assumptions. And those assumptions should be made carefully and in a very transparent manner.

What do I mean by the basics of the scope of portfolio analysis? There are a bunch of questions. Should the analysis be focusing on

California or should we look at a greater geography? If we are focused on WECC, it brings consistency across the region, but there are jurisdictional issues; and I'm not sure if the Commission wants to go there.

Then who should conduct the analysis, and how? Should CEC be conducting the analysis as OPA is doing? Or if utilities are going to be doing them, then how will we guarantee the consistency and comparability of those studies?

The utility portfolio choices are interdependent, especially when it comes to CO_2 emissions and so on. The optimal portfolio, or the portfolio which is close to be the optimum, depends on what the other utilities are doing at the same time.

What discount rate or risk tolerance should be used for purposes of representing the California ratepayer. I know that there's a risk tolerance number, but that should be a little bit -- it should be calculated a little bit more rigorously, and specifically it should take reality of the loss load into account.

In a simple risk return space, how do we pick the optimal portfolio. In a multi-dimensional risk return space, if there are more than one measures of return, or the effects in CO2 emissions and so on, how are we going to make the decision?

The aim is to determine the optimal portfolio. And, of course, it's evaluation through time for each of the utility. And we need to, I think, consider the look at the scenarios of the futures. What the future is going to look like; what are the states of the world that we are looking at.

We have to bundle events somehow together so that those scenarios are (inaudible). Portfolios are choice variables, and scenarios are not. That's one important point. There are more than one methodology, as I said. Starting out with the reference portfolio is -- makes analysis and portfolio choice easier, but it's less robust to structural changes. And limits portfolio choice in the long run. And is going to be harder to get a consensus on, as we see in the PacifiCorp case.

Defining portfolios ahead of scenarios also limit the portfolio choice. Must be flexible under the considered scenario considerations so that the portfolios depend on scenarios and not the other way around.

Political considerations and other constraints should be factored in. As I said before, over and over again, looking only at the financial side of the analysis will not cut it.

Other costs and benefits of portfolios; environmental impact, local considerations, long-term reliability, CO2 and so on and so forth should be considered. They should be in the return paper.

A selection criteria should be agreed on before going into the analysis in a fair, transparent and efficiency-enhancing way. One way to do it is to come up with a scorecard with a well-defined point system for each category.

But agreeing on the method brings the discussions at the front, at the beginning of the study, so it's actually a lot more efficient if you just do something, some study and then present the results. Then the discussions will be a little bit more (inaudible). And once again, as we see in the PacifiCorp case, even though they say that they did it transparently, it's going to be inefficient and postponing RFPs and somehow investment issues will be arising.

And finally, stochastic risk and scenario risk should be handled separately and carefully, I must say. Identifying several scenarios that are considered likely should be done.

Portfolio selections must be analyzed separately under each scenario. The scenarios considered to -- don't have an optimal number attend, but there's a tradeoff. The higher the number of scenarios or the futures you consider, the higher the amount of effort and assumptions that you need to make.

A simulation-type exercise is probably something that we cannot get rid of. We need to do that. Probably we need to combine that with a dispatch model to look at the hourly price of electricity, to come up with a better estimate of it.

And here's the results. The roadmap for California planning should be in really really really basic terms. Should start with identifying the scenarios. What scenarios, what states of the world do we think are likely in the future.

When I say that, we should clearly

include some of the doomsday scenarios in here. So what if something goes really really bad, what is the plan. The plan should also address that point to a certain extent.

It also comes back to the risk tolerance determination. How tolerant are we to a doomsday scenario. Do we want to plan for it and pay the costs or not.

After that, given the scenarios, we should identify the portfolios. And we should be as specific as possible in terms of the individual assets. But looking from let's say 20 years from today, clearly we will not name assets, but we will be talking about probably fuel types. And given the assumptions on technology, of course.

But we should be as specific as possible, especially for the resources which exist today that we can name, given the discount rate, given the fact that the closer it is the more important it gets.

We should identify the relationships between key drivers and portfolio performances. When I say performances, it's true time. A mix of dispatch model and regression analysis; and of course, the simulations are necessary.

We should relate how various factors interact with each other and decide the assumptions for the factors can be taken either simulation or -- analysis, but it should be robust statistically.

And finally probably that's going to be the biggest item on the agenda. We should calculate the scorecards for the results. How do we weigh different categories of results. And how do we make a decision on it.

That concludes my presentation. And I hope I stayed in the timeframe. And I am very happy to see if there are any questions.

CHAIRPERSON PFANNENSTIEL: Thank you. Are there questions here? None here. Thank you very much.

DR. BAHCECI: Thank you.

CHAIRPERSON PFANNENSTIEL: Dave, I need to leave to go to another meeting. But my able colleagues will carry on.

MR. VIDAVER: I'm only going to be about three minutes or so, if you care to stay.

On the agenda the section is listed as implementation issues and suggestions for further research. I think I'm going to offer more in the way of closing comments and questions. So, if in response to those comments and questions anyone cares to comment, I'd appreciate their doing so.

In the absence of that, we will be taking written comments over the next, I believe it's ten day. Instructions on how to submit written comments are contained in the workshop notice, which is posted on the Commission website.

I'd like to thank all the presenters today for providing a very illuminating set of, I would say answers, but I think they've posed as many questions as they've provided answers.

The use of increasingly complex models to evaluate an increasing number of risks presents challenges to utilities and to the regulatory community. This is moreso the case as we look at longer run risks associated with the price of natural gas, development costs for the yet to fully mature generation technologies, and mandated reductions of unknown quantities in greenhouse gas emissions.

Data needs increase as we try to model an increasing number of variables and their interrelationships, and do so over longer time periods.

Longer run risks are more difficult to assess, as the presenters have pointed out, as we can no longer safely assume that historical data will adequately describe the set of possible futures and their likelihoods. Market-driven estimates, such as futures prices, cease to exist.

The time paths of the most important variables, for example, the development costs of various technologies become little more than informed conjecture. One need only look at the assumptions made by Southern California Edison, not to single them out, regarding the possible future costs of renewable energy at different levels of penetration, to see the consensus regarding the underlying probability distributions of key variables may be difficult to achieve.

How then do we move forward, given uncertainty regarding so many key variables. Choosing among responses to a utility's RFO clearly requires modeling the dispatch of that utility's portfolio, as the previous presenter indicated, subject to numerous constraints presented by the physical system.

And it requires the expertise of utility staff using the tools refined over the years for that purpose. But where gas and nongas resources are in competition, or more generally, can a complete or informative set of risk assessments be performed. One that considers in greater detail the potential impacts of changes in greenhouse gas cost and the long-run gas price.

And can and should the net present value of these resources be evaluated at different discount rates. Doing so would provide a better understanding of the risks inherent in selecting specific resources, and the relationship between the value of time and our choices for generation technologies.

How can the aforementioned risks be better assessed in the longer term context of resource planning as currently practiced. Is it feasible to expect utilities to use a model such as the one developed by the Northwest Power and Conservation Council, given their current tools.

More importantly, would it be of value, given the significant role played by the variables, whose future values are subject to substantial uncertainty.

If utilities differ dramatically in their characterizations of possible futures, how can their assessments be used to inform policy.

Finally, if the continued analysis of a limited number of utility portfolios is, for whatever reasons, many of which have been laid out here, the most feasible method of undertaking resource planning, how can it be better designed where the results presented so as to provide an improved understanding of the longer term risks faced by utility ratepayers, and the relative value of different portfolios. And how can these risks, themselves, be better modeled.

These are among the questions with which we're concerned, among the questions you've contributed to answer and raised more questions about. And again, we ask for your input in written form, and your participation in the Committee workshop scheduled for July 11th. We hope to have a draft staff report out for comment about three weeks prior to that workshop.

So, if -- Dr. Strauss, pardon me.

DR. STRAUSS: Thanks, Dave. And I think it would be useful at least -- this may come across as self-serving, so I apologize; feel free to slap me down -- but when I look at the Ontario Power Authority analysis, and when I look at the

PacifiCorp analysis, it has a very, you know, similar look and feel to the analysis I presented this morning. And so I, you know, would ask the Commission to recognize that.

If one looked at our 2004 long-term plan, we should rightly be criticized for neglecting a lot of those features. But if one looks at our latest long-term plan, it actually has a very similar look and feel to these kinds of studies.

When one compares it to the Northwest Power Planning Council, I think it's -- there are a couple differences. And I think if you think about level of sophistication, I think it's pretty clear that their analysis is higher on the sophistication scale, as I mentioned early this morning. That's necessarily neither good nor bad, it's just a way to characterize it.

I'd just note it differs in two notable ways, and, Michael, please correct me otherwise. One is that they attached explicit probabilities to particular scenarios. And the other is more in the way they operationalize, characterize the contingent nature of particular plants. And we actually have some of that in our candidate plans, but there's a lot more of that in a lot more detailed kind of way in what they do. And I recognize that.

And for statewide planning I, you know, see some merit in doing it that way. For utility planning, procurement, particularly in the way the cycles have been set up in every two years for the utility to file a plan at the Utilities Commission, we're actually kind of -- and I can contrast this, this is language that Michael and I speak, you know, if you'll bear with me, but it's the difference between sort of closed-loop feedback and open-loop feedback, you know.

Basically, every two years we go to the Utility Commission, say here's a couple things we're thinking about for relatively next few years, taking action. And here's some of the long-term consequences. And we'll be back in two years later, and the world will have changed differently. We'll be back with a newer snapshot, a new assessment, and a new set of sort of next couple of steps.

Whereas in the Northwest Power and Planning Council model there's a lot more sort of modeling within that tool, and within the framework of a whole bunch of contingent actions going out a pretty far horizon.

So, again, that may be useful for statewide planning. And I'd just note that for the kind of procurement-oriented planning that we're doing at the Utility Commission, and for utility procurement, you know, that's part of why there's some differences there.

But I, you know, as folks respectfully disagree with. Thank you.

COMMISSIONER GEESMAN: I again want to thank you for being here, because I do think your participation has been extremely helpful.

I take pretty strong exception to the approach that you've taken, and actually think the state would be quite a bit better served if we were a lot closer to the Northwest Planning Council's end of the spectrum.

I'm particularly troubled by this moral hazard problem, which I think probably haunts any fuel-intensive utility system. And I have no objection to fuel-cost pass-throughs, don't get me wrong. But I do think it puts a higher burden on the regulator and the planning process to try and evolve fairly quickly out of what I would characterize as an excessive dependence on fuel-intensive resources. To me that colors a lot.

I also believe that we would be better served by a longer term planning horizon than occurs in the procurement setting. I also think, in response to some of the things that Rob Anderson said from San Diego, that over the course of the last three or four years you've had enough of the fundamental building blocks of state policy come into pretty clear focus, that I would really start from those assumptions and build forward.

It's a very fast-moving area, as I think we all are suffering from, but I do think that we can do this a lot better than we've been doing it.

And, again, I salute you for your willingness to sit through this and share your thoughts with us. It has been helpful to me.

COMMISSIONER BYRON: The IEPR process this Commission continues to focus on shows the important, but difficult, issues that we're continuing to face here. I had no idea how problematic and complicated the electric procurement process was until I joined this Commission.

It's clear to me, as a result of today

and previous meetings, that the IOUs have to deal with a plethora of objectives and constraints imposed on them by law and regulation.

But I'm also cognizant of those that aren't written down in law or regulation, the ones that are objectives that the utilities impose on themselves, which are often in conflict with the needs, perhaps, of the state and the very customers they serve.

I focused today on an issue that bothered me, and it's perhaps tangent to a lot of the presentations, and that's this transparency issue that, among other things, maybe contributing to this problem.

Commissioner Geesman, unless you have anything else to add, I think we may be done here today.

COMMISSIONER GEESMAN: You and I have a status conference or prehearing conference in this very room --

COMMISSIONER BYRON: I do, as well.

COMMISSIONER GEESMAN: -- that was to start ten minutes ago.

COMMISSIONER BYRON: Oh, it's in B. Do we have any public comments, any others from the audience that wish to comment here?

I'd like to thank the participants very much for being here. Appreciate all the time and effort that you've put into being here. Thank you to the staff very much.

I think we're adjourned.

(Whereupon, at 3:10 p.m., the Staff Workshop was adjourned.)

--o0o--

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 Staff 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 11th day of June, 2007.